Kosmos Energy Ltd.
Form 10-Q
November 05, 2018
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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 September 30, 2018
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 001-35167

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

Bermuda	98-0686001
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Clarendon House
2 Church Street

Hamilton, Bermuda	HM 11
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: +1 441 295 5950

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 November 1, 2018
Common Shares, $0.01 par value	433,617,302

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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.

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KOSMOS ENERGY LTD.
GLOSSARY AND SELECTED ABBREVIATIONS

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

"2D seismic data"	Two-dimensional seismic data, serving as interpretive data that allows a view of a vertical cross-section beneath a prospective area.
"3D seismic data"	Three-dimensional seismic data, serving as geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic data.
"API"	A specific gravity scale, expressed in degrees, that denotes the relative density of various petroleum liquids. The scale increases inversely with density. Thus lighter petroleum liquids will have a higher API than heavier ones.
"ASC"	Financial Accounting Standards Board Accounting Standards Codification.
"ASU"	Financial Accounting Standards Board Accounting Standards Update.
"Barrel" or "Bbl"	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
"BBbl"	Billion barrels of oil.
"BBoe"	Billion barrels of oil equivalent.
"Bcf"	Billion cubic feet.
"Boe"	Barrels of oil equivalent. Volumes of natural gas converted to barrels of oil using a conversion factor of 6,000 cubic feet of natural gas to one barrel of oil.
"Boepd"	Barrels of oil equivalent per day.
"Bopd"	Barrels of oil per day.
"Bwpd"	Barrels of water per day.
"Debt cover ratio"	The "debt cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) total long-term debt less cash and cash equivalents and restricted cash, to (y) the aggregate EBITDAX (see below) of the Company for the previous twelve months.
"Developed acreage"	The number of acres that are allocated or assignable to productive wells or wells capable of production.
"Development"	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.

“Dry hole" or "Unsuccessful well”	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.

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"EBITDAX"	Net income (loss) plus (i) exploration expense, (ii) depletion, depreciation and amortization expense, (iii) equity based compensation expense, (iv) unrealized (gain) loss on commodity derivatives (realized losses are deducted and realized gains are added back), (v) (gain) loss on sale of oil and gas properties, (vi) interest (income) expense, (vii) income taxes, (viii) loss on extinguishment of debt, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results. The Facility EBITDAX definition includes 50% of the EBITDAX adjustments of Kosmos-Trident International Petroleum Inc and includes Last Twelve Months ("LTM") EBITDAX for any acquisitions and excludes LTM EBITDAX for any divestitures.
"E&P"	Exploration and production.
"FASB"	Financial Accounting Standards Board.
"Farm-in"	An agreement whereby a party acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and/or for taking on a portion of future costs or other performance by the assignee as a condition of the assignment.
"Farm-out"	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash and/or for the assignee taking on a portion of future costs and/or other work as a condition of the assignment.
"Field life cover ratio"	The "field life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) the forecasted net present value of net cash flow through depletion plus the net present value of the forecast of certain capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets, to (y) the aggregate loan amounts outstanding under the Facility.
"FPS"	Floating production system.
"FPSO"	Floating production, storage and offloading vessel.
"Interest cover ratio"	The "interest cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) the aggregate EBITDAX (see above) of the Company for the previous twelve months, to (y) interest expense less interest income for the Company for the previous twelve months.
"Loan life cover ratio"	The "loan life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of forecasted net cash flow through the final maturity date of the Facility plus the net present value of forecasted capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets, to (y) the aggregate loan amounts outstanding under the Facility.
"LNG"	Liquefied natural gas.
"MBbl"	Thousand barrels of oil.
"MBoe"	Thousand barrels of oil equivalent.
"Mcf"	Thousand cubic feet of natural gas.

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"Mcfpd"	Thousand cubic feet per day of natural gas.
"MMBbl"	Million barrels of oil.
"MMBoe"	Million barrels of oil equivalent.
"MMcf"	Million cubic feet of natural gas.
"MMcfd"	Million cubic feet per day of natural gas.
"Natural gas liquid" or "NGL"	Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.
"Petroleum contract"	A contract in which the owner of hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
"Petroleum system"	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
"Plan of development" or "PoD"	A written document outlining the steps 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.
"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.

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

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"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.
"Undeveloped acreage"	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains discovered resources.

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

	September 30, 2018 (Unaudited)	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 192,646	$ 233,412
Restricted cash	5,376	56,380
Receivables:		
Joint interest billings, net	84,209	134,565
Oil sales	131,546	—
Related party	20,834	780
Other	15,750	25,616
Inventories	90,003	71,861
Prepaid expenses and other	58,949	9,306
Derivatives	41,466	1,682
Total current assets	640,779	533,602
Property and equipment:		
Oil and gas properties, net	3,498,855	2,310,973
Other property, net	10,682	6,855
Property and equipment, net	3,509,537	2,317,828
Other assets:		
Equity method investment	88,652	236,514
Restricted cash	9,473	15,194
Long-term receivables - joint interest billings	21,861	34,941
Deferred financing costs, net of accumulated amortization of $11,411 and $13,951 at September 30, 2018 and December 31, 2017, respectively	9,582	2,510
Deferred tax assets	31,890	22,517
Derivatives	14,486	39
Other	3,204	29,458
Total assets	$ 4,329,464	$ 3,192,603
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 153,922	$ 141,787
Accrued liabilities	262,310	219,412
Derivatives	212,217	67,531
Total current liabilities	628,449	428,730
Long-term liabilities:		
Long-term debt, net	2,094,534	1,282,797
Derivatives	110,245	30,209
Asset retirement obligations	150,200	66,595
Deferred tax liabilities	401,826	476,548
Other long-term liabilities	9,277	10,612
Total long-term liabilities	2,766,082	1,866,761
Shareholders' equity:		

Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at September 30, 2018 and December 31, 2017	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 442,856,360 and 398,599,457 issued at September 30, 2018 and December 31, 2017, respectively	4,429	3,986
Additional paid-in capital	2,331,969	2,014,525
Accumulated deficit	(1,352,758)	(1,073,202)
Treasury stock, at cost, 9,263,269 and 9,188,819 shares at September 30, 2018 and December 31, 2017, respectively	(48,707)	(48,197)
Total shareholders’ equity	934,933	897,112
Total liabilities and shareholders’ equity	$ 4,329,464	$ 3,192,603

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues and other income:				
Oil and gas revenue	$242,833	$151,240	$585,220	$391,035
Gain on sale of assets	7,666	—	7,666	—
Other income, net	(280)	2	(17)	58,697
Total revenues and other income	250,219	151,242	592,869	449,732
Costs and expenses:				
Oil and gas production	55,078	39,187	151,661	80,677
Facilities insurance modifications, net	12,334	(3,906)	21,812	(1,334)
Exploration expenses	148,238	36,983	246,912	162,679
General and administrative	25,963	20,029	65,343	50,555
Depletion and depreciation	80,041	73,490	208,607	180,909
Interest and other financing costs, net	23,549	18,478	68,113	54,729
Derivatives, net	57,357	26,864	236,107	(36,404)
(Gain) loss on equity method investments, net	(24,841)	4,804	(59,637)	11,230
Other expenses, net	(12,807)	233	(8,164)	3,003
Total costs and expenses	364,912	216,162	930,754	506,044
Loss before income taxes	(114,693)	(64,920)	(337,885)	(56,312)
Income tax expense (benefit)	11,364	(1,515)	(58,329)	44,401
Net loss	$(126,057)	$(63,405)	$(279,556)	$(100,713)
Net loss per share:				
Basic	$(0.31)	$(0.16)	$(0.70)	$(0.26)
Diluted	$(0.31)	$(0.16)	$(0.70)	$(0.26)
Weighted average number of shares used to compute net loss per share:				
Basic	404,536	389,058	399,026	388,114
Diluted	404,536	389,058	399,026	388,114

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(In thousands)

(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Treasury	
	Shares	Amount	Capital	Deficit	Stock	Total
Balance as of December 31, 2017	398,599	$ 3,986	$2,014,525	$(1,073,202)	$(48,197)	$897,112
Acquisition of oil and gas properties	34,994	350	307,594	—	—	307,944
Equity-based compensation	—	—	27,128	—	—	27,128
Restricted stock awards and units	9,263	93	(93)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(17,185)	—	(510)	(17,695)
Net loss	—	—	—	(279,556)	—	(279,556)
Balance as of September 30, 2018	442,856	$ 4,429	$2,331,969	$(1,352,758)	$(48,707)	$934,933

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
Operating activities		
Net loss	$(279,556)	$(100,713)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	215,676	188,563
Deferred income taxes	(84,095)	32,820
Unsuccessful well costs	114,948	24,515
Change in fair value of derivatives	232,057	(25,924)
Cash settlements on derivatives, net (including $(107.3) million and $36.4 million on commodity hedges during 2018 and 2017)	(102,705)	25,275
Equity-based compensation	25,975	29,945
Gain on sale of assets	(7,666)	—
Loss on extinguishment of debt	4,324	—
Distributions in excess of equity in earnings	5,235	11,230
Other	1,237	3,412
Changes in assets and liabilities:		
Decrease in receivables	59,318	3,232
Decrease in inventories	3,978	58
Increase in prepaid expenses and other	(9,732)	(19,327)
Decrease in accounts payable	(15,178)	(120,325)
Increase (decrease) in accrued liabilities	(73,569)	41,651
Net cash provided by operating activities	90,247	94,412
Investing activities		
Oil and gas assets	(149,305)	(100,712)
Other property	(3,560)	(1,639)
Acquisition of oil and gas properties, net of cash acquired	(961,764)	—
Return of investment from KTIPI	142,628	—
Proceeds on sale of assets	13,703	222,068
Net cash provided by (used in) investing activities	(958,298)	119,717
Financing activities		
Borrowings under long-term debt	1,000,000	—
Payments on long-term debt	(175,000)	(250,000)
Purchase of treasury stock / tax withholdings	(17,695)	(2,116)
Deferred financing costs	(36,745)	—
Net cash provided by (used in) financing activities	770,560	(252,116)
Net decrease in cash, cash equivalents and restricted cash	(97,491)	(37,987)
Cash, cash equivalents and restricted cash at beginning of period	304,986	273,195
Cash, cash equivalents and restricted cash at end of period	$207,495	$235,208

Supplemental cash flow information

Cash paid for:		
Interest	$86,981	$48,694
Income taxes	$25,601	$27,199
Non-cash activity:		
Contribution to equity method investment	$—	$133,893
Common stock issued for acquisition of oil and gas properties	$307,944	$—

See accompanying notes.

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KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements
(Unaudited)

1. Organization

Kosmos Energy Ltd. was incorporated pursuant to the laws of Bermuda in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Holdings is a privately held Cayman Islands company that was formed in March 2004. As a holding company, Kosmos Energy Ltd.'s corporate 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 Margin. 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 short-cycle 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.

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

2. Accounting Policies

General

The interim-period financial information presented in the consolidated financial statements included in this report is unaudited and, in the opinion of management, includes all adjustments of a normal recurring nature necessary to present fairly the consolidated financial position as of September 30, 2018, the changes in the consolidated statements of shareholders' equity for the nine months ended September 30, 2018, the consolidated results of operations for the three and nine months ended September 30, 2018 and 2017, and the consolidated cash flows for the nine months ended September 30, 2018 and 2017. 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, 2017, 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 impact on our reported net loss, current assets, total assets, current liabilities, total liabilities, shareholders' equity or cash flows.

Cash, Cash Equivalents and Restricted Cash

	September 30, 2018	December 31, 2017
	(In thousands)	
Cash and cash equivalents	$192,646	$ 233,412
Restricted cash - current	5,376	56,380
Restricted cash - long-term	9,473	15,194
Total cash, cash equivalents and restricted cash shown in the consolidated statement of cash flows	$207,495	$ 304,986

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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 petroleum contract, the requirement to post the existing letters of credit will be satisfied and the cash collateral will be released. However, additional letters of credit may be required should we choose to move into the next phase of certain of our petroleum contracts. As of September 30, 2018 and December 31, 2017, we had $5.4 million and $31.6 million, respectively, of current restricted cash and $9.2 million and $15.2 million, respectively, of long-term restricted cash used to collateralize performance guarantees related to our petroleum contracts. As of September 30, 2018, we also had $0.2 million in other long-term restricted cash.

In addition, prior to our reserves based debt facility (the "Facility") being amended and restated in February 2018, we were required to maintain a restricted cash balance that was sufficient to meet the payment of interest and fees for the next six-month period on the 7.875% Senior Secured Notes due 2021 (“Senior Notes”) plus the Corporate Revolver, or the Facility, whichever was greater. As of December 31, 2017, we had $24.8 million in current restricted cash to meet this requirement. Under the amended and restated Facility, we are no longer required to maintain a restricted cash balance provided we are compliant with certain financial covenant ratios.

Inventories

Inventories consisted of $86.8 million (including $22.1 million acquired through the Deep Gulf Energy (together with its subsidiaries "DGE") acquisition) and $63.5 million of materials and supplies and $3.2 million and $8.4 million of hydrocarbons as of September 30, 2018 and December 31, 2017, respectively. The Company’s materials and supplies inventory primarily consists of casing and wellheads and is stated at the lower of cost, using the weighted average cost method, or net realizable value.

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.

Revenue Recognition

We use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of September 30, 2018 and December 31, 2017, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when production has been sold to a purchaser at a fixed or determinable price, title has transferred and collectability is probable. Certain revenues are based on provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The embedded derivative, which is not designated as a hedge, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month after the sale.
Oil and gas revenue is composed of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Revenue from contracts with customers - Ghana	$215,581	$157,461	$557,459	$401,816
Revenue from contracts with customers - U.S. Gulf of Mexico	24,177	—	24,177	—
Provisional oil sales contracts	3,075	(6,221)	3,584	(10,781)
Oil and gas revenue	$242,833	$151,240	585,220	391,035

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Recent Accounting Standards

Recently Adopted

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in ASC Topic 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 applies to all contracts with customers except those that are within the scope of other topics in the FASB ASC. The new guidance is effective for annual reporting periods beginning after December 15, 2017 for public companies. Entities have the option of using either a full retrospective or modified retrospective approach to adopt ASU 2014-09. The Company adopted the new standard during the first quarter of 2018 using the modified retrospective approach and there is no impact to our previously recorded revenue under the new standard.

In March 2018, the FASB issued ASU 2018-05, “Income Taxes (Topic 740).” ASU 2018-05 was issued to include amendments to SEC paragraphs pursuant to SEC Staff Accounting Bulletin No. 118 ("SAB 118") and addresses certain circumstances that may arise for registrants in accounting for the income tax effects of the Tax Cut and Jobs Act (the "Tax Reform Act"), including when certain income tax effects of the Tax Reform Act are incomplete by the time the financial statements are issued.

Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” ASU 2016-02 was issued to increase transparency and comparability across organizations by recognizing substantially all leases on the balance sheet through the concept of right-of-use lease assets and liabilities. Under current accounting guidance, lessees do not recognize lease assets or liabilities for leases classified as operating leases. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years with early adoption permitted. The new leasing standard requires the modified retrospective adoption method. The Company is in the process of evaluating its contract population to determine the impact of this accounting standard on its consolidated financial statements.

3. Acquisitions and Divestitures

2018 Transactions

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

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

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 and $307.9 million in Kosmos common stock and $14.9 million of transaction related costs. We funded the cash portion of the purchase price using cash on hand and drawings under our existing credit facilities. We also received $200.0 million of additional firm commitments under the Facility, which provides further liquidity to the Company. The DGE acquisition was accounted for under the asset acquisition method and the purchase price allocation is shown below. The purchase price allocation was based on the estimated relative fair value of identifiable assets acquired and liabilities assumed.

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

	Purchase Price Allocation (in thousands)
Fair value of assets acquired:	
Proved oil and gas properties	$1,045,509
Unproved oil and gas properties	300,420
Accounts receivable and other	179,332
Total assets acquired	$1,525,261
Fair value of liabilities assumed:	
Accrued liabilities and other	$123,034
Asset retirement obligations	86,580
Derivative liabilities	40,265
Total liabilities assumed	$249,879
Cash consideration paid	$952,586
Fair value of common stock(1)	307,944
Transaction related costs	14,852
Total purchase price	$1,275,382

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

As a result of the DGE acquisition, we have included $24.2 million of revenues and $4.4 million of direct operating expenses in our consolidated statements of operations for the period from September 14, 2018 to September 30, 2018.

In October 2018, Kosmos entered into a strategic exploration alliance with Shell Exploration Company B.V. (“Shell”) to jointly explore in Southern West Africa. Initially the alliance will focus on Namibia where Kosmos has completed a farm-in to Shell's acreage in PEL 39.

2017 Transactions

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

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In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. In August 2018, we closed a farm-out agreement with Trident, whereby they acquired a 40% participating interest in blocks EG-21, S, and W, resulting in a $7.7 million gain. After giving effect to the farm-out agreement, we hold a 40% participating interest and are the operator in all three blocks. The Equatorial Guinean national oil company, Guinea Equatorial De Petroleos ("GEPetrol"), has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the effective date (March 2018). The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes a 6,000 square kilometer 3D seismic acquisition requirement across the three blocks.

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

4. Joint Interest Billings and Related Party Receivables

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

In 2014, the Ghana National Petroleum Corporation (“GNPC”) notified us and our block partners of its request for the contractor group to pay GNPC’s 5% share of the Tweneboa, Enyenra and Ntomme (“TEN”) development costs. The block partners are being reimbursed for such costs plus interest out of a portion of GNPC’s TEN production revenues. As of September 30, 2018 and December 31, 2017, the current portions of the joint interest billing receivables due from GNPC for the TEN fields development costs were $14.0 million and $15.2 million, respectively, and the long-term portions were $21.9 million and $31.6 million, respectively.

The Company's related party receivables consists primarily of receivables from Trident who owns a 50% interest in KTIPI. As of September 30, 2018 the balance due from Trident consists of $13.7 million related to the farm-out of Blocks EG-21, S, and W, and $7.1 million related to joint interest billings for the exploration blocks and Kosmos' support of KTIPI operations.

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5. Property and Equipment

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

	September 30, 2018	December 31, 2017
	(In thousands)	
Oil and gas properties:		
Proved properties	$2,749,163	$1,653,616
Unproved properties	733,274	465,109
Support equipment and facilities	1,450,907	1,427,054
Total oil and gas properties	4,933,344	3,545,779
Accumulated depletion	(1,434,489)	(1,234,806)
Oil and gas properties, net	3,498,855	2,310,973
Other property	46,513	39,405
Accumulated depreciation	(35,831)	(32,550)
Other property, net	10,682	6,855
Property and equipment, net	$3,509,537	$2,317,828

We recorded depletion expense of $76.8 million and $70.9 million for the three months ended September 30, 2018 and 2017, respectively, and $199.7 million and $173.3 million for the nine months ended September 30, 2018 and 2017, respectively.

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6. Suspended Well Costs

The following table reflects the Company's capitalized exploratory well costs on completed wells as of and during the nine months ended September 30, 2018. The table excludes $48.0 million in costs that were capitalized and subsequently expensed during the same period.

	September 30, 2018
	(In thousands)
Beginning balance	$ 410,113
Additions associated with the acquisition of DGE	26,426
Additions to capitalized exploratory well costs pending the determination of proved reserves	7,658
Reclassification due to determination of proved reserves	—
Capitalized exploratory well costs charged to expense	(52,498)
Ending balance	$ 391,699

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:

	September 30, 2018	December 31, 2017
	(In thousands, except well counts)	
Exploratory well costs capitalized for a period of one year or less	$ 26,426	$ 67,159
Exploratory well costs capitalized for a period of one to two years	296,866	291,252
Exploratory well costs capitalized for a period of three years	68,407	51,702
Ending balance	$ 391,699	$ 410,113
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	5

As of September 30, 2018, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Greater Tortue discovery, which crosses the Mauritania and Senegal maritime border, the BirAllah discovery (formerly known as the Marsouin discovery) in Block C8 offshore Mauritania and the Yakaar and Teranga discoveries in the Cayar Offshore Profond block offshore Senegal.

Akasa Discovery — As a result of discussions during our quarterly Ghana partner meetings in October 2018, we determined sufficient progress has not been made to continue to capitalize the costs associated with the Akasa discovery. As a result, we wrote off $39.8 million of previously capitalized costs to exploration expense during the third quarter of 2018. We retain our rights associated with the Akasa discovery area, and the acreage is not currently being relinquished.

Wawa Discovery — As a result of discussions during our quarterly Ghana partner meetings in October 2018, we determined sufficient progress has not been made to continue to capitalize the costs associated with the Wawa discovery. As a result, we wrote off $17.9 million of previously capitalized costs to exploration expense during the third quarter of 2018. We retain our rights associated with the Wawa discovery area, and the acreage is not currently being relinquished.

Greater Tortue Discovery — In May 2015, we completed the Tortue-1 exploration well in Block C8 offshore Mauritania, which encountered hydrocarbon pay. Two additional wells have been drilled in the Greater Tortue

Discovery area, Ahmeyim-2 in Mauritania and Guembeul-1 in Senegal. We completed a drill stem test on the Tortue 1 well in August 2017, which confirmed the production capabilities of the Greater Tortue Discovery. Data acquired from the drill stem test will be used to further optimize field development and to refine process design parameters critical to the Front End Engineering Design ("FEED") process. The partnership has made significant progress towards a final investment decision for phase one. Led by BP, the FEED work for phase one is substantially complete. The Unit Development Plan has been submitted to both governments, and we have reached agreement with the Governments of Mauritania and Senegal on the non-PSA fiscal terms for this cross border project.

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BirAllah Discovery — In November 2015, we completed the Marsouin-1 exploration well (renamed BirAllah) in the northern part of Block C8 offshore Mauritania which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality is expected to be made.
Yakaar and Teranga Discoveries — In May 2016, we completed the Teranga-1 exploration well in the Cayar Offshore Profond block offshore Senegal which encountered hydrocarbon pay. In June 2017, we completed the Yakaar-1 exploration well in the Cayar Offshore Profond block offshore Senegal which encountered hydrocarbon pay. In November 2017, an integrated Yakaar-Teranga appraisal plan was submitted. An appraisal well is scheduled in 2019 to further evaluate the discovery. Following additional evaluation, a decision regarding commerciality is expected to be made.

Nearly Headless Nick Discovery — In September 2018, the Nearly Headless Nick exploration well (22.0% WI) was successfully drilled to a total depth of approximately 5,800 meters (19,050 feet) and encountered approximately 26 meters (85 feet) of net pay in the Middle Miocene objective within the Mississippi Canyon 387 block offshore U.S. Gulf of Mexico. Nearly Headless Nick will be developed as a subsea tie back, which is expected to be brought online through the Delta House facility by 2020.

7. Equity Method Investments
Kosmos BP Senegal Limited ("KBSL")

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

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

During the three and nine months ended September 30, 2017 we recognized $4.8 million and $11.2 million, respectively, related to our share of losses in KBSL. Our initial contribution to KBSL was $133.9 million, which was recorded at our carrying costs.

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Equatorial Guinea

As part of our acquisition of KTIPI, a corporate joint venture entity in which we own 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.

	September 30, 2018	December 31, 2017
	(In thousands)	
Assets		
Total current assets	$158,140	$179,070
Property and equipment, net	291,960	345,611
Other assets	487	567
Total assets	$450,587	$525,248
Liabilities and shareholders' equity		
Total current liabilities	$196,338	$106,769
Total long-term liabilities	541,881	565,591
Shareholders' equity:		
Total shareholders' equity	(287,632)	(147,112)
Total liabilities and shareholders' equity	$450,587	$525,248

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
	(In thousands)	
Revenues and other income:		
Oil and gas revenue	$215,408	$600,158
Other income	(72)	44
Total revenues and other income	215,336	600,202
Costs and expenses:		
Oil and gas production	40,334	115,366
Depletion and depreciation	33,044	108,996
Other expenses, net	(58)	(211)
Total costs and expenses	73,320	224,151
Income before income taxes	142,016	376,051
Income tax expense	50,796	134,047
Net income	$91,220	$242,004
Kosmos' share of net income	$45,610	$121,002
Basis difference amortization(1)	20,769	61,365
Equity in earnings - KTIPI	$24,841	$59,637

(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.

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When evaluating our equity method investments for impairment, we review our ability to recover the carrying amount of such investments or the entity's ability to sustain earnings that justify its carrying amount. As of September 30, 2018, we determined that we had the ability to recover the carrying amount of our equity method investment in KTIPI. As such, no impairment has been recorded. Our initial investment has been increased for our net share of equity in earnings as adjusted for our basis differential and reduced by cash dividends received. During the nine months ended September 30, 2018, we received $207.5 million of cash dividends from KTIPI, and we received an additional $32.5 million of cash dividends in October 2018.

8. Debt

	September 30, 2018	December 31, 2017
	(In thousands)	
Outstanding debt principal balances:		
Facility	$1,325,000	$800,000
Corporate Revolver	300,000	—
Senior Notes	525,000	525,000
Total	2,150,000	1,325,000
Unamortized deferred financing costs and discounts(1)	(55,466)	(42,203)
Long-term debt, net	$2,094,534	$1,282,797

(1) Includes $40.3 million and $23.6 million of unamortized deferred financing costs related to the Facility and $15.2 million and $18.6 million of unamortized deferred financing costs and discounts related to the Senior Notes as of September 30, 2018 and December 31, 2017, respectively.

Facility

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. In August 2018, the Company entered into letter agreements with two existing financial institutions, which obligate the two financial institutions to provide the Company, upon the Company's election, with an additional commitment of $200 million in the aggregate under the Facility. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net in the first quarter of 2018. As of September 30, 2018, we have $40.3 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. As of September 30, 2018, borrowings under the Facility totaled $1,325.0 million and the undrawn availability under the Facility was $375.0 million, which includes the $200 million in additional commitments referenced above.

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 September 30, 2018, we had no letters of credit issued under the Facility.

We were in compliance with the financial covenants contained in the Facility as of September 30, 2018 (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%

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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 September 30, 2018, borrowings under the Corporate Revolver totaled $300 million and the undrawn availability under the Corporate Revolver was $100 million. As of September 30, 2018, we have $9.6 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 September 30, 2018 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

We have a revolving letter of credit facility agreement ("LC Facility"), which matures in July 2019. In July 2018, the LC Facility size was voluntarily reduced to $40.0 million based on the expiration of several large outstanding letters of credit. As of September 30, 2018, there were eight outstanding letters of credit totaling $16.9 million under the LC Facility. The LC Facility contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

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

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

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

At September 30, 2018, the estimated repayments of debt during the five fiscal year periods and thereafter are as follows:

	Payments Due by Year						
	Total	2018(2)	2019	2020	2021	2022	Thereafter
	(In thousands)						
Principal debt repayments(1)	$2,150,000	$ —	$ —	$ —	$685,600	$589,100	$875,300

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015, borrowings under the Facility and the Corporate Revolver. The scheduled maturities of debt related to the Facility are based on, as of September 30, 2018, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled

maturities of debt during the next five years and thereafter.

(2) Represents payments for the period October 1, 2018 through December 31, 2018.

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Interest and other financing costs, net

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Interest expense	$27,317	$22,961	$77,121	$68,934
Amortization—deferred financing costs	2,346	2,551	7,069	7,653
Loss on extinguishment of debt	268	—	4,324	—
Capitalized interest	(7,097)	(8,563)	(21,209)	(25,498)
Deferred interest	(194)	662	(1,284)	1,610
Interest income	(788)	(745)	(2,579)	(2,485)
Other, net	1,697	1,612	4,671	4,515
Interest and other financing costs, net	$23,549	$18,478	$68,113	$54,729

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 September 30, 2018. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

				Weighted Average Price per Bbl					
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling	Call
2018:									
Oct — Dec	Swap with puts	Dated Brent	1,500	$—	$56.75	$43.33	$—	$—	$ —
Oct — Dec	Three-way collars	Dated Brent	733	0.74	—	41.57	56.57	65.91	—
Oct — Dec	Four-way collars	Dated Brent	751	1.06	—	40.00	50.00	61.33	70.00
Oct — Dec	Sold calls(1)	Dated Brent	503	—	—	—	—	65.00	—
Oct — Dec	Purchased Calls	Dated Brent	500	1.88	—	—	—	—	70.00
Oct — Dec	Purchased Puts	NYMEX WTI	141	2.70	—	—	53.00	—	—
Oct — Dec	Collars	NYMEX WTI	35	—	—	—	62.29	66.35	—
Oct — Dec	Swaps	NYMEX WTI	698	—	54.69	—	—	—	—
2019:									

Jan — Dec	Three-way collars	Dated Brent	10,500	$1.17	$—	$43.81	$53.33	$73.58	$ —
Jan — Dec	Sold calls(1)	Dated Brent	913	—	—	—	—	80.00	—
Jan — Dec	Swaps	NYMEX WTI	1,747	—	52.31	—	—	—	—
Jan — Jun	Collars	NYMEX WTI	339	—	—	—	57.77	63.70	—
Jan — Dec	Collars	Argus LLS	1,000	—	—	—	60.00	88.75	—
2020:									
Jan — Dec	Three-way collars	Dated Brent	2,000	$—	$—	$50.00	$60.00	$90.54	$ —
Jan — Dec	Sold calls(1)	Dated Brent	8,000	$—	$—	$—	$—	$80.00	$ —

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

Interest Rate Derivative Contracts

The following table summarizes our capped interest rate swaps whereby we pay a fixed rate of interest if LIBOR is below the cap, and pay the market rate less the spread between the cap (sold call) and the fixed rate of interest if LIBOR is above the cap as of September 30, 2018:

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

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The following tables disclose the Company's derivative instruments as of September 30, 2018 and December 31, 2017 and gain/(loss) from derivatives during the three months ended September 30, 2018 and 2017, respectively:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) September 30, 2018	December 31, 2017
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$40,953	$ 665
Interest rate	Derivatives assets—current	513	1,017
Commodity(2)	Derivatives assets—long-term	14,486	39
Derivative liabilities:			
Commodity(3)	Derivatives liabilities—current	(212,217)	(67,531)
Commodity(4)	Derivatives liabilities—long-term	(110,245)	(30,209)
Total derivatives not designated as hedging instruments		$(266,510)	$ (96,019)

(1) Includes net deferred premiums payable of $4.7 million and net deferred premiums receivable of $0.8 million related to commodity derivative contracts as of September 30, 2018 and December 31, 2017, respectively.
(2) Includes net deferred premiums payable of $2.4 million and net deferred premiums receivable of $0.1 million related to commodity derivative contracts as of September 30, 2018 and December 31, 2017, respectively.
(3) Includes net deferred premiums payable of $6.0 million and $5.6 million related to commodity derivative contracts as of September 30, 2018 and December 31, 2017, respectively.
(4) Includes net deferred premiums payable of $1.6 million and $4.8 million related to commodity derivative contracts as of September 30, 2018 and December 31, 2017, respectively.

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Three Months Ended September 30, 2018	2017	Amount of Gain/(Loss) Nine Months Ended September 30, 2018	2017
		(In thousands)			
Derivatives not designated as hedging instruments:					
Commodity(1)	Oil and gas revenue	$3,075	$(6,221)	$3,584	$(10,781)
Commodity	Derivatives, net	(57,357)	(26,864)	(236,107)	36,404
Interest rate	Interest expense	15	64	466	301
Total derivatives not designated as hedging instruments		$(54,267)	$(33,021)	$(232,057)	$25,924

(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 September 30, 2018 and December 31, 2017, there was not an event of default and, therefore, the associated gross asset or gross liability amounts related to these arrangements are presented on the consolidated balance sheets.

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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 September 30, 2018 and December 31, 2017, 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)			
September 30, 2018				
Assets:				
Commodity derivatives	$ —	$ 55,439	$ —	$ 55,439
Interest rate derivatives	—	513	—	513
Liabilities:				
Commodity derivatives	—	(322,462)	—	(322,462)
Total	$ —	$ (266,510)	$ —	$ (266,510)
December 31, 2017				
Assets:				
Commodity derivatives	$ —	$ 704	$ —	$ 704
Interest rate derivatives	—	1,017	—	1,017
Liabilities:				
Commodity derivatives	—	(97,740)	—	(97,740)
Total	$ —	$ (96,019)	$ —	$ (96,019)

The book values of cash and cash equivalents and restricted cash approximate fair value based on Level 1 inputs. Joint interest billings, oil sales 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.

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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.

Interest Rate Derivatives

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

Debt

The following table presents the carrying values and fair values at September 30, 2018 and December 31, 2017:

	September 30, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$510,766	$535,941	$507,600	$542,472
Corporate Revolver	300,000	300,000	—	—
Facility	1,325,000	1,325,000	800,000	800,000
Total	$2,135,766	$2,160,941	$1,307,600	$1,342,472

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

11. Equity-based Compensation

Restricted Stock Awards and 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 $8.9 million and $9.6 million during the three months ended September 30, 2018 and 2017, respectively, and $26.0 million and $29.9 million during the nine months ended September 30, 2018 and 2017, respectively. The total tax benefit for the three months ended September 30, 2018 and 2017 was $1.6 million and $3.2 million, respectively, and $5.0 million and $9.9 million during the nine months ended September 30, 2018 and 2017, respectively. Additionally, we recorded a net tax shortfall (windfall) related to equity-based compensation of $0.1 million and $0.2 million for the three months ended September 30, 2018 and 2017, respectively, and $(0.3) million and $3.1 million during the nine months ended September 30, 2018 and 2017, respectively. The fair value of
awards vested during the three months ended September 30, 2018 and 2017 was approximately $1.1 million and $1.4 million, respectively, and $83.1 million and $20.7 million during the nine months ended September 30, 2018 and 2017, respectively. The Company granted both restricted stock awards and restricted stock units with service vesting criteria and granted both restricted stock awards and restricted stock units with a combination of market and service vesting criteria under the LTIP. Substantially all these grants vest over three years. Restricted stock awards are issued and included in the number of outstanding shares upon the date of grant and, if such awards are forfeited, they become treasury stock. Upon vesting, restricted stock units become issued and outstanding stock.

The following table reflects the outstanding restricted stock awards as of September 30, 2018:

	Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2017	220	$ 8.64
Granted	—	—
Forfeited	—	—
Vested	(220)	8.64
Outstanding at September 30, 2018	—	—

The following table reflects the outstanding restricted stock units as of September 30, 2018:

	Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2017	4,183	$ 6.39	8,452	$ 11.26
Granted(1)(2)	2,360	7.03	8,140	12.39
Forfeited	(116)	6.49	(46)	9.74
Vested	(2,173)	6.93	(9,545)	13.75
Outstanding at September 30, 2018	4,254	6.41	7,001	9.17

(1) The restricted stock units with a combination of market and service vesting criteria include 4.9 million shares granted as a result of the 2014 and 2015 awards achieving 200% of their respective market performance conditions.

(2) The restricted stock units with a combination of market and service vesting criteria include 0.7 million shares granted to DGE employees as part of a new hire grant upon becoming employees of Kosmos. These shares were valued at $12.93 per share based on the Monte Carlo simulation model.

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As of September 30, 2018, total equity-based compensation to be recognized on unvested restricted stock units is $36.2 million over a weighted average period of 2.05 years. In January 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 shareholders 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 September 30, 2018, the Company had approximately 15.8 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 $15.71 per award. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies and ranged from 44.0% to 53.0% . The risk-free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant and ranged from 0.7% to 2.2%.

12. Income Taxes

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis 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.

On December 22, 2017, the President of the United States signed P.L. 115-97, the Tax Reform Act into law. SAB 118 was issued in January 2018 to address situations where certain aspects of the Jobs Act are unclear at issuance of a registrant's financial statements for the reporting period in which the Jobs Act became law. SAB 118 allows us to record provisional amounts during a one-year measurement period. We are analyzing certain aspects of the Jobs Act which could affect the measurement of deferred tax balances.

The income tax provision consists of United States and Ghanaian income and Texas margin taxes. 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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Bermuda	$(15,513)	$(17,740)	$(47,474)	$(50,680)
United States	(53,136)	1,437	(49,967)	4,231
Foreign—other	(46,044)	(48,617)	(240,444)	(9,863)
Income (loss) before income taxes	$(114,693)	$(64,920)	$(337,885)	$(56,312)

Our effective tax rate for the three months ended September 30, 2018 and 2017 is 10% and 2%, respectively. For the nine months ended, September 30, 2018 and 2017, our effective tax rate was 17% and 79%, respectively. For the periods ended September 30, 2018 and 2017 our overall effective tax rates were 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 Ghana and the United States. The Company is open to Ghanaian federal income tax examinations for tax years 2014 through 2017 and in the United States, to federal income tax examinations for tax years 2014 through 2017.

As of September 30, 2018, the Company had no material uncertain tax positions. The Company’s policy is to recognize potential interest and penalties related to income tax matters in income tax expense.

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13. Net Loss Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Numerator:				
Net loss	$(126,057)	$(63,405)	$(279,556)	$(100,713)
Basic income allocable to participating securities(1)	—	—	—	—
Basic net loss allocable to common shareholders	(126,057)	(63,405)	(279,556)	(100,713)
Diluted adjustments to income allocable to participating securities(1)	—	—	—	—
Diluted net loss allocable to common shareholders	$(126,057)	$(63,405)	$(279,556)	$(100,713)
Denominator:				
Weighted average number of shares outstanding:				
Basic	404,536	389,058	399,026	388,114
Restricted stock awards and units(1)(2)	—	—	—	—
Diluted	404,536	389,058	399,026	388,114
Net loss per share:				
Basic	$(0.31)	$(0.16)	$(0.70)	$(0.26)
Diluted	$(0.31)	$(0.16)	$(0.70)	$(0.26)

(1) Our service vesting restricted stock awards represent participating securities because they participate in non-forfeitable dividends with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Our restricted stock awards with market and service vesting criteria and all restricted stock units are not considered to be participating securities and, therefore, are excluded from the basic net loss per common share calculation. Our service vesting restricted stock awards do not participate in undistributed net losses because they are not contractually obligated to do so and, therefore, are excluded from the basic net loss per common share calculation in periods we are in a net loss position.

(2) We excluded outstanding restricted stock awards and units of 13.1 million and 12.9 million for the three months ended September 30, 2018 and 2017, respectively, and 14.5 million and 12.9 million for the nine months ended September 30, 2018 and 2017, respectively, from the computations of diluted net 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 Mauritania and two exploration wells in Senegal. Our partner is obligated to fund our share of the cost of the exploration wells, subject to the remaining exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Equatorial Guinea and Sao Tome and Principe, we have 3D seismic requirements of approximately 9,000 square kilometers and 13,500 square kilometers, respectively.

Future minimum rental commitments under our leases at September 30, 2018, are as follows:

	Payments Due By Year(1)						
	Total	2018(2)	2019	2020	2021	2022	Thereafter
	(In thousands)						
Operating leases(3)	$37,971	$ 1,463	$2,775	$4,173	$3,276	$3,326	$ 22,958

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(1) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator or discrete purchases of long lead items purchased through normal operations and excludes commitments for exploration activities, including well commitments, in our petroleum contracts.

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(2) Represents payments for the period from October 1, 2018 through December 31, 2018.
(3) Primarily relates to corporate office and foreign office leases.

Performance Obligations

As of September 30, 2018, the Company had secured performance bonds totaling $214 million for our supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management ("BOEM") and $4 million to another operator related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its U.S. Gulf of Mexico fields. As of September 30, 2018, we had $0.6 million of cash collateral against these secured performance bonds which is classified as Other long term assets in our consolidated balance sheet.

15. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	September 30, 2018	December 31, 2017
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$101,767	$ 144,717
Current asset retirement obligations	11,161	—
General and administrative expenses	27,902	31,124
Interest	7,430	20,457
Income taxes	7,618	17,423
Taxes other than income	3,457	3,270
Derivatives	21,704	825
Acquired liabilities	80,783	—
Other	488	1,596
	$262,310	$ 219,412

Gain on sale of assets

During the three and nine months ended September 30, 2018, we recognized a $7.7 million gain related to the farm-out of Blocks EG-21, S and W to Trident.

Other Income, Net

Other income, net which includes Loss of Production Income ("LOPI") payments in 2017, consisted of zero and $58.7 million for the nine months ended September 30, 2018 and 2017, respectively. Our LOPI coverage for the turret bearing issue on the Jubilee FPSO ended in May 2017.

Oil and Gas Production

Oil and gas production expense included insurance recoveries related to our increased cost of working covered by our LOPI policy of zero and $17.1 million for the nine months ended September 30, 2018 and 2017, respectively.

Facilities Insurance Modifications, Net

Facilities insurance modifications, net consists of costs associated with the long-term solution to convert the Jubilee FPSO to a permanently spread moored facility which we expect to recover from our insurance policy net of any insurance reimbursements.

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Other Expenses, Net

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
(Gain) loss on disposal of inventory	$(2)	$(500)	$(26)	$47
Gain on insurance settlements	—	—	—	(461)
Disputed charges and related costs, net of recoveries	(12,682)	821	(9,721)	3,260
Other, net	(123)	(88)	1,583	157
Other expenses, net	$(12,807)	$233	$(8,164)	$3,003

The disputed charges and related costs are expenditures arising from Tullow Ghana Limited’s contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow charged such expenditures to the Deepwater Tano (“DT”) joint account. Kosmos disputed through arbitration that these expenditures were chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement. In July 2018, the International Chamber of Commerce ("ICC") issued its Final Award in the arbitration in favor of Kosmos. As a result, we recovered from Tullow Ghana Limited disputed charges in the amount of $12.9 million in the form of cash payments and offsets against other unrelated joint venture costs, which include amounts previously paid under protest as well as certain costs and fees incurred pursuing the arbitration.

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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, 2017, 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 Margin. 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 short-cycle 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

Shell Alliance

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

Deep Gulf Energy Acquisition

In September 2018, we completed the acquisition of Deep Gulf Energy (together with its subsidiaries "DGE"), a deepwater company operating in the U.S. Gulf of Mexico, from First Reserve Corporation and other shareholders for a total consideration of $1.275 billion, comprised of $952.6 million in cash and $307.9 million in Kosmos common stock and $14.9 million of transaction related costs. We funded the cash portion of the purchase price using cash on hand and drawings under our existing credit facilities. We also received $200 million of additional firm commitments under the Facility, which provides further liquidity to the Company.

As part of the DGE transaction, Kosmos acquired a portfolio of short-cycle growth assets, including a high-quality inventory of exploration prospects. During the third quarter, the Nearly Headless Nick prospect (22.0% WI) was successfully drilled to a total depth of 5,807 meters (19,052 feet) and encountered approximately 26 meters (85 feet) of net pay in the Middle Miocene objective within the Mississippi Canyon 387 block. Nearly Headless Nick, a subsea tie back, which is expected to be brought online through the Delta House facility by 2020, adds near-term reserves and production growth.

During the third quarter of 2018, Kosmos expanded its inventory as one of the most active participants in U.S. Gulf of Mexico Lease Sale 251 with apparent high bids on seven deepwater blocks. As part of the Company’s strategy to expand its position in the U.S. Gulf of Mexico, Kosmos incurred approximately $50 million of exploration expense to acquire seismic over new prospective areas and to re-license seismic over existing fields during the third quarter.

In late September, a second development well was brought online at Odd Job in Mississippi Canyon Block 215 (54.9% WI) and connected to the Delta House facility, providing near-term growth at the field. A third Odd Job well located in Mississippi Canyon Block 214 (61.1% WI) drilled in May 2018 is expected to start production through existing subsea infrastructure to the Delta House facility by early 2020.

Gulf of Mexico production during the period from transaction close until the end of the third quarter averaged approximately 24,200 boepd.

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Corporate

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

Our revolving letter of credit facility agreement ("LC Facility") has flexibility that allows us to increase or decrease the available amount as needed if the existing lender increases its commitment or if commitments from new financial institutions are added. In July 2018, the LC Facility size was voluntarily reduced to $40.0 million based on the expiration of several large outstanding letters of credit.

Ghana

Jubilee

During the third quarter of 2018, Jubilee production averaged approximately 94,300 bopd as one new producer well was brought online, with a second expected in the fourth quarter of 2018. Production from these wells, together with enhancements to gas handling capacity, is expected to increase production towards the FPSO nameplate capacity of 120,000 bopd. With regards to the turret remediation work, we expect rotation of the vessel to take place around the end of 2018 with minimal impact to production in 2018.

The financial impact of lower Jubilee production, as well as the additional expenditures associated with the damage to the turret bearing, is mitigated through a combination of the comprehensive Hull and Machinery insurance (“H&M”), procured by the operator, Tullow, on behalf of the Jubilee Unit partners, and through May 2017, the corporate Loss of Production Income (“LOPI”) insurance procured by Kosmos.

Tweneboa, Enyenra and Ntomme ("TEN")

During the third quarter of 2018, TEN production averaged approximately 62,600 bopd as one new producer well at Ntomme came online. Kosmos expects this well to support current production levels of approximately 65,000 to 70,000 bopd through the end of the year when a second new production well is due to be brought online to increase production towards the FPSO nameplate capacity. The TEN FPSO has previously been tested at rates above the 80,000 bopd nameplate capacity, and Kosmos expects to further test this capacity in 2019 as additional wells come online.

Other

A second rig, which arrived in September, is being used for drilling operations, with the current rig set up for a continuous completion program. Taking advantage of low rig rates in the current environment is expected to accelerate the addition of new wells in Ghana, increasing production towards FPSO capacity sooner, with the goal of achieving gross production from Jubilee and TEN of 180,000 to 200,000 bopd over the next three years.

In June 2016, Kosmos Energy Ghana HC filed a Request for Arbitration with the International Chamber of Commerce ("ICC") against Tullow Ghana Limited in connection with a dispute arising under the DT Joint Operating Agreement. At dispute was Kosmos Energy Ghana HC’s responsibility for expenditures arising from Tullow Ghana Limited’s contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow sought to charge such expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputed that these expenditures were chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement and that the Seadrill West Leo drilling rig contract had not been entered into in connection with joint operations.

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

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Greater Tortue

The partnership has made significant progress towards a final investment decision for phase one. Led by BP, the front end engineering and design ("FEED") work for phase one is substantially complete. The Unit Development Plan has been submitted to both governments, and we have reached agreement with the Governments of Mauritania and Senegal on the non-PSA fiscal terms for this cross border project.

Senegal

In July 2018, we entered into the second renewal of the exploration period for the Senegal Blocks contract areas, which lasts for two and one half years. Each of the contract areas requires one exploration well to be drilled during the second renewal period. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for at least one additional period of 10 years under certain circumstances.

Equatorial Guinea

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

In May 2018, we began a 3D seismic survey of approximately 9,500 square kilometers over blocks EG-21, EG-24, S and W offshore Equatorial Guinea, and approximately 200 square kilometers over Block G which is operated by our equity method investment in Kosmos-Trident International Petroleum Inc. ("KTIPI"). The seismic will be processed with the objective of high grading prospects for drilling in 2019.

In August 2018, we completed a farm-out agreement with a subsidiary of Trident Energy (“Trident”), covering blocks S, W and EG21 offshore Equatorial Guinea resulting in a $7.7 million gain. Under the terms of the agreement, Trident acquired a 40% non-operated participating interest in the blocks and Kosmos remains the operator.

Production in Equatorial Guinea averaged approximately 42,600 bopd in the third quarter. Through October 2018, Kosmos has received approximately $240 million in dividends from the Kosmos-Trident joint venture (over 100 percent of the $231 million purchase price), which equates to a payback of less than one year.

Suriname

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

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

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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 our equity method investment offshore Equatorial Guinea. Certain operating results and statistics for the three and nine months ended September 30, 2018 and 2017 are included in the following tables:

	Three Months Ended September 30, 2018			Nine Months Ended September 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)	3,247	1,448	4,695	8,076	4,278	12,354
Gas (MMcf)	309	—	309	309	—	309
NGL (MBbl)	24	—	24	24	—	24
Total (MBoe)	3,323	1,448	4,771	8,152	4,278	12,430
Revenues:						
Oil sales	$241,139	$ 107,704	$348,843	$583,526	$ 300,079	$883,605
Average oil sales price per Bbl	74.27	74.38	74.30	72.25	70.14	71.52
Gas sales	975	—	975	975	—	975
Average gas sales price per Mcf	3.16	—	3.16	3.16	—	3.16
NGL sales	719	—	719	719	—	719
Average NGL sales price per Bbl	29.96	—	29.96	29.96	—	29.96
Costs:						
Oil and gas production, excluding workovers	$55,363	$ 20,167	$75,530	$149,517	$ 57,683	$207,200
Oil and gas production, workovers	(285)	—	(285)	2,144	—	2,144
Total oil and gas production costs	$55,078	$ 20,167	$75,245	$151,661	$ 57,683	$209,344
Depletion and depreciation	$80,041	$ 37,291	$117,332	$208,607	$ 115,862	$324,469
Average cost per Boe:						
Oil and gas production, excluding workovers	$16.66	$ 13.93	$15.83	$18.34	$ 13.48	$16.67
Oil and gas production, workovers	(0.09)	—	(0.06)	0.26	—	0.17
Total oil and gas production costs	16.57	13.93	15.77	18.60	13.48	16.84
Depletion and depreciation	24.09	25.75	24.59	25.59	27.08	26.10
Oil and gas production cost and depletion costs	$40.66	$ 39.68	$40.36	$44.19	$ 40.56	$42.94

(1) For the three and nine months ended September 30, 2018, we have presented our 50% share of the results of operations, including our basis difference which is reflected in depletion and depreciation. Under the equity method of accounting, we only recognize our share of the net income of KTIPI as adjusted for our basis differential, which is recorded in (gain) loss on equity method investments, net in the consolidated statement of operations.

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	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
	(In thousands, except per barrel data)	
Sales volumes (MBbl):		
Oil	2,939	7,830
Revenues:		
Oil and gas sales	$ 151,240	$ 391,035
Average sales price per Bbl	51.46	49.94
Costs:		
Oil and gas production, excluding workovers	$ 38,118	$ 79,110
Oil and gas production, workovers	1,069	1,567
Total oil and gas production costs	$ 39,187	$ 80,677
Depletion and depreciation	$ 73,490	$ 180,909
Average cost per Bbl:		
Oil and gas production, excluding workovers	$ 12.97	$ 10.10
Oil and gas production, workovers	0.36	0.20
Total oil and gas production costs	13.33	10.30
Depletion and depreciation	25.01	23.10
Oil and gas production cost and depletion costs	$ 38.34	$ 33.40

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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 September 30, 2018:

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	1	0.24	—	—	9	2.17
West Cape Three Points	—	—	—	—	2	0.62	—	—
TEN	—	—	—	—	—	—	5	0.85
Deepwater Tano	—	—	—	—	1	0.18	—	—
U.S. Gulf of Mexico								
Mississippi Canyon 214	—	—	—	—	—	—	1	0.61
Mississippi Canyon 387	—	—	—	—	1	0.22	—	—
Mauritania								
C8	—	—	—	—	3	0.84	—	—
Senegal								
Saint Louis Offshore Profond	—	—	—	—	1	0.30	—	—
Cayar Profond	—	—	—	—	2	0.60	—	—
Suriname								
Block 42	1	0.33	—	—	—	—	—	—
Total	1	0.33	1	0.24	10	2.76	15	3.63

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

Three months ended September 30, 2018 compared to three months ended September 30, 2017

	Three Months Ended September 30,		Increase
	2018	2017	(Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$242,833	$151,240	$91,593
Gain on sale of assets	7,666	—	7,666
Other income, net	(280)	2	(282)
Total revenues and other income	250,219	151,242	98,977
Costs and expenses:			
Oil and gas production	55,078	39,187	15,891
Facilities insurance modifications, net	12,334	(3,906)	16,240
Exploration expenses	148,238	36,983	111,255
General and administrative	25,963	20,029	5,934
Depletion and depreciation	80,041	73,490	6,551
Interest and other financing costs, net	23,549	18,478	5,071
Derivatives, net	57,357	26,864	30,493
(Gain) loss on equity method investment, net	(24,841)	4,804	(29,645)
Other expenses, net	(12,807)	233	(13,040)
Total costs and expenses	364,912	216,162	148,750
Loss before income taxes	(114,693)	(64,920)	(49,773)
Income tax expense (benefit)	11,364	(1,515)	12,879
Net loss	$(126,057)	$(63,405)	$(62,652)

Oil and gas revenue. Oil and gas revenue increased by $91.6 million primarily as a result of higher oil prices during the three months ended September 30, 2018, compared to the three months ended September 30, 2017. We sold 3,247 MBbl at an average realized price per barrel of $74.27 during the three months ended September 30, 2018 and 2,939 MBbl at an average realized price per barrel of $51.46 during the three months ended September 30, 2017.

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

Oil and gas production. Oil and gas production costs increased by $15.9 million during the three months ended September 30, 2018, as compared to the three months ended September 30, 2017. This is a result of insurance proceeds recognized related to Jubilee turret operating costs as well as credit accrual adjustments from the operator of the Jubilee and TEN fields during the three months ended September 30, 2017. Additionally, we incurred $4.5 million of oil and gas production costs for the U.S. Gulf of Mexico for the period from September 14, 2018 through September 30, 2018.

Facilities insurance modifications, net. During the three months ended September 30, 2018, we incurred $12.3 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue. During the three months ended September 30, 2017, we incurred $3.3 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue. No insurance proceeds were received in the three months ended September 30, 2018, while the three months period ended September 30, 2017 were offset by

$7.2 million of hull and machinery insurance proceeds.

Exploration expenses. Exploration expenses increased by $111.3 million during the three months ended September 30, 2018, as compared to the three months ended September 30, 2017. The increase is primarily a result of the determination that a declaration of commerciality was not currently warranted for the Akasa-1 and the Wawa-1 exploration wells, resulting in a write

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off of $57.7 million, and $12.6 million of unsuccessful well costs related to Suriname drilling. Additionally, we incurred approximately $50.0 million related to seismic acquisition costs in the U.S. Gulf of Mexico as well as increases in other seismic and geological and geophysical costs for the three months ended September 30, 2018. These increases were partially offset by $21.0 million of unsuccessful well costs for the Mauritania Hippocampe-1 exploration well incurred during the three months ended September 30, 2017.

General and administrative. General and administrative costs increased by $5.9 million during the three months ended September 30, 2018, as compared with the three months ended September 30, 2017. The increase is driven primarily by integration costs related to the DGE acquisition and to a lesser extent the loss of our ability to charge out certain costs associated with the transfer of operatorship of the Tortue development project and WCTP Block to BP and Tullow, respectively.

Depletion and depreciation. Depletion and depreciation increased $6.6 million during the three months ended September 30, 2018, as compared with the three months ended September 30, 2017. The increase is primarily a result of first time depletion and depreciation costs associated with the acquired U.S. Gulf of Mexico properties.

Derivatives, net. During the three months ended September 30, 2018 and 2017, we recorded a loss of $57.4 million and a loss of $26.9 million, respectively, on our outstanding hedge positions. The losses recorded were a result of changes in the forward curve of oil prices during the respective periods.

(Gain) loss on equity method investment, net. (Gain) loss on equity method investment, net resulted in a $29.6 million positive impact compared to 2017 as a result of a $24.8 million gain on our equity method investment in KTIPI in 2018, compared to a $4.8 million loss recognized on our equity method investment in Kosmos BP Senegal Limited ("KBSL") in 2017 with no contribution from KTIPI since the acquisition had not closed.

Other expenses, net. Other expenses, net decreased $13.0 million primarily related to the recovery of disputed charges of $12.9 million related to the arbitration award against Tullow Ghana.

Income tax expense (benefit). For the three months ended September 30, 2018, the Company recognized a net tax benefit because of pre-tax losses related to our Ghanaian operations. For the periods ended September 30, 2018 and 2017 our overall effective tax rates were 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.

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Nine months ended September 30, 2018 compared to nine months ended September 30, 2017

	Nine Months Ended September 30,		Increase
	2018	2017	(Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$585,220	$391,035	$194,185
Gain on sale of assets	7,666	—	7,666
Other income, net	(17)	58,697	(58,714)
Total revenues and other income	592,869	449,732	143,137
Costs and expenses:			
Oil and gas production	151,661	80,677	70,984
Facilities insurance modifications, net	21,812	(1,334)	23,146
Exploration expenses	246,912	162,679	84,233
General and administrative	65,343	50,555	14,788
Depletion and depreciation	208,607	180,909	27,698
Interest and other financing costs, net	68,113	54,729	13,384
Derivatives, net	236,107	(36,404)	272,511
(Gain) loss on equity method investment, net	(59,637)	11,230	(70,867)
Other expenses, net	(8,164)	3,003	(11,167)
Total costs and expenses	930,754	506,044	424,710
Loss before income taxes	(337,885)	(56,312)	(281,573)
Income tax expense (benefit)	(58,329)	44,401	(102,730)
Net loss	$(279,556)	$(100,713)	$(178,843)

Oil and gas revenue. Oil and gas revenue increased by $194.2 million primarily as a result of higher oil prices during the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017. We sold 8,076 MBbl at an average realized price per barrel of $72.25 during the nine months ended September 30, 2018 and 7,830 MBbl at an average realized price per barrel of $49.94 during the nine months ended September 30, 2017. No U.S. Gulf of Mexico acquisition related barrels are included in the 2017 period.

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

Other income, net. Other income, net decreased by $58.7 million as we recognized $58.7 million of LOPI proceeds, net during the nine months ended September 30, 2017 related to the turret bearing issue on the Jubilee FPSO. The LOPI claim was finalized in June 2017.

Oil and gas production. Oil and gas production costs increased by $71.0 million during the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017 primarily as a result of finalized LOPI claim insurance proceeds recognized related to increased costs due to turret issues as well as credit accrual adjustments from the operator of the Jubilee and TEN fields operator recognized during the nine months ended September 30, 2017. No U.S. Gulf of Merixo acquisition related production costs are included in the 2017 period.

Facilities insurance modifications, net. During the nine months ended September 30, 2018, we incurred $31.5 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue. These costs were offset by $9.7 million of hull and machinery insurance proceeds received during the nine months ended September 30, 2018, resulting in a net charge of $21.8 million. During the nine months ended September 30, 2017, we incurred $13.6 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue. These costs were offset by $14.9 million of insurance proceeds received during the nine months ended September 30, 2017 resulting in a credit of $1.3 million.

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Exploration expenses. Exploration expenses increased by $84.2 million during the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017. The change is primarily a result of $42.1 million of stacked rig costs associated with the ENSCO DS-12 (formerly the Atwood Achiever) and a $48.1 million cancellation payment related to the exercise of our election to cancel the fourth year option of the ENSCO DS-12 drilling rig contract, both recorded during the nine months ended September 30, 2017. These decreases were offset by $57.1 million of unsuccessful well costs related to Suriname drilling and $57.7 million of unsuccessful well costs for the Wawa-1 and Akasa-1 exploration wells which were previously capitalized as suspended well costs. Additionally, we incurred approximately $50.0 million related to seismic acquisition costs in the U.S. Gulf of Mexico as well as increases in other seismic and geological and geophysical costs.

General and administrative. General and administrative costs increased by $14.8 million during the nine months ended September 30, 2018, as compared with the nine months ended September 30, 2017. The increase is driven by integration costs related to the DGE acquisition and the loss of our ability to charge out certain costs associated with the transfer of operatorship of the Tortue development project and WCTP Block to BP and Tullow, respectively. No U.S. Gulf of Mexico acquisition related G&A costs are included in the 2017 period.

Depletion and depreciation. Depletion and depreciation increased $27.7 million during the nine months ended September 30, 2018, as compared with the nine months ended September 30, 2017. The increase is primarily a result of a higher depletion rate for the TEN fields as 2018 had three Jubilee and two TEN liftings compared to four Jubilee and one TEN lifting in 2017. Additionally, the Jubilee Field depletion increased as a result of costs associated with the Mahogany and Teak discovery areas moving into the Jubilee Field's depletable cost basis in the fourth quarter of 2017. No U.S. Gulf of Mexico acquisition related DD&A costs are included in the 2017 period.

Interest and other financing costs, net. Interest and other financing costs, net increased $13.4 million primarily a result of expensing $4.3 million of existing unamortized debt issuance costs and deferred interest in connection with amending the Facility in first quarter 2018 and a $9.1 million increase in interest related to a higher average interest rate and outstanding debt balance, the result of the DGE acquisition.

Derivatives, net. During the nine months ended September 30, 2018 and 2017, we recorded a loss of $236.1 million and a loss of $36.4 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. (Gain) loss on equity method investment, net resulted in a $59.6 million gain on our equity method investment in KTIPI in 2018, compared to a $11.2 million loss recognized on our equity method investment in KBSL in 2017.

Other expenses, net. Other expenses, net decreased $11.2 million primarily related to the recovery of disputed charges of $12.9 million related to the arbitration award against Tullow Ghana.

Income tax expense (benefit). For the nine months ended September 30, 2018, the Company recognized a net tax benefit because of pre-tax losses related to our Ghanaian operations. For the periods ended September 30, 2018 and 2017 our overall effective tax rates were 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 exploring for and developing oil and natural gas resources along the Atlantic Margins and also continue to evaluate inorganic opportunities. 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 remaining capital program for 2018.

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Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Sources of cash, cash equivalents and restricted cash:		
Net cash provided by operating activities	$90,247	$94,412
Return of investment from KTIPI	142,628	—
Borrowings under long-term debt	1,000,000	—
Proceeds on sale of assets	13,703	222,068
	1,246,578	316,480
Uses of cash, cash equivalents and restricted cash:		
Oil and gas assets	149,305	100,712
Other property	3,560	1,639
Acquisition of oil and gas properties	961,764	—
Payments on long-term debt	175,000	250,000
Purchase of treasury stock	17,695	2,116
Deferred financing costs	36,745	—
	1,344,069	354,467
Decrease in cash, cash equivalents and restricted cash	$(97,491)	$(37,987)

Net cash provided by operating activities. Net cash provided by operating activities for the nine months ended September 30, 2018 was $90.2 million compared with net cash provided by operating activities for the nine months ended September 30, 2017 of $94.4 million. The decrease in cash provided by operating activities in the nine months ended September 30, 2018 when compared to the same period in 2017 is primarily a result of an increase in oil and gas revenue and a decrease in exploration expenses related to the stacked rig costs and rig option cancellation payment, both recorded during the nine months ended September 30, 2017 offset by a decrease in LOPI proceeds, net, an increase in unsuccessful well costs and an increase in payments related to derivative cash settlements.

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The following table presents our net debt and liquidity as of September 30, 2018:

	September 30, 2018 (In thousands)
Cash and cash equivalents	$ 192,646
Restricted cash	14,849
Senior Notes at par	525,000
Drawings under the Facility	1,325,000
Drawings under the Corporate Revolver	300,000
Net debt	$ 1,942,505
Availability under the Facility(1)	$ 375,000
Availability under the Corporate Revolver	$ 100,000
Available borrowings plus cash and cash equivalents	$ 667,646

(1) Includes letter agreements with two existing financial institutions, which obligate the two financial institutions to provide the Company, upon the Company's election, with an additional commitment of $200 million in the aggregate under the Facility.

Capital Expenditures and Investments

We expect to incur capital costs as we:
- drill additional wells in the Jubilee and TEN Fields and in the U.S. Gulf of Mexico;
- fund asset integrity projects at Jubilee;
- execute exploration and appraisal 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. 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, severe weather, 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.

2018 Capital Program

We estimate we will spend approximately $400 million of capital, excluding the DGE purchase price and net of carry amounts related to the Mauritania and Senegal transactions with BP, for the year ending December 31, 2018. 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 September 30, 2018, we have spent approximately $264.0 million.

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Significant Sources of Capital

Facility

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. In August 2018, the Company entered into letter agreements with two existing financial institutions, which obligate the two financial institutions to provide the Company, upon the Company's election, with an additional commitment of $200 million in the aggregate under the Facility. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net in the first quarter of 2018. As of September 30, 2018, we have $40.3 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility.

The Facility provides a revolving credit and letter of credit facility. The availability period for the revolving credit facility expires one month prior to the final maturity date. The letter of credit facility expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on March 31, 2022, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2025. As of September 30, 2018, we had no letters of credit issued under the Facility.

We were in compliance with the financial covenants contained in the Facility as of September 30, 2018 (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 September 30, 2018, borrowings under the Corporate Revolver totaled $300 million and the undrawn availability under the Corporate Revolver was $100 million. We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2018 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

We have a revolving letter of credit facility agreement (“LC Facility”), which matures in July 2019. In July 2018, the LC Facility size was voluntarily reduced to $40.0 million based on the expiration of several large outstanding letters of credit. As of September 30, 2018, there were eight outstanding letters of credit totaling $16.9 million under the LC Facility. The LC Facility contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

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

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

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The Senior Notes mature on August 1, 2021. Interest is payable semi-annually in arrears each February 1 and August 1 commencing on February 1, 2015 for the initial $300.0 million Senior Notes and August 1, 2015 for the additional $225.0 million Senior Notes. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all shares held by us in our direct subsidiary, Kosmos Energy Holdings. The Senior Notes are currently guaranteed on a subordinated, unsecured basis by our existing restricted subsidiaries that guarantee both the Facility and the Corporate Revolver, and, in certain circumstances, the Senior Notes will become guaranteed by certain of our other existing or future restricted subsidiaries. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" section of our annual report on Form 10-K for the terms of the Senior Notes.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of September 30, 2018:

	Payments Due By Year(4)						
	Total	2018(5)	2019	2020	2021	2022	Thereafter
	(In thousands)						
Principal debt repayments(1)	$2,150,000	$ —	$ —	$ —	$685,600	$589,100	$875,300
Interest payments on long-term debt(2)	642,439	25,211	149,238	153,080	145,564	77,596	91,750
Operating leases(3)	37,971	1,463	2,775	4,173	3,276	3,326	22,958

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015, borrowings under the Facility and the Corporate Revolver. The scheduled maturities of debt related to the Facility are based on the level of borrowings and the estimated future available borrowing base as of September 30, 2018. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

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

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

(4) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator or discrete purchases of long lead items purchased through normal operations and excludes commitments for exploration activities, including well commitments and seismic obligations, in our petroleum contracts.

(5) Represents the period from October 1, 2018 through December 31, 2018.

We currently have a commitment to drill one exploration well in Mauritania and two exploration wells in Senegal. Our partner is obligated to fund our share of the cost of the exploration wells, subject to the remaining exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Equatorial Guinea and Sao Tome and Principe, we have 3D seismic requirements of approximately 9,000 square kilometers and 13,500 square kilometers, respectively.

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

	Years Ending December 31,						Asset (Liability) Fair Value at September 30,
	2018(5)	2019	2020	2021	2022	Thereafter	2018
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$—	$—	$—	$525,000	$—	$—	$(535,941)
Fixed interest rate	7.88%	7.88%	7.88%	7.88%	—	—	
Variable rate debt:							
Facility(1)	$—	$—	$—	$160,600	$289,100	$875,300	$(1,325,000)
Corporate Revolver	—	—	—	—	300,000	—	(300,000)
Weighted average interest rate(2)	5.87%	6.35%	6.58%	6.60%	6.55%	6.88%	
Capped interest rate swaps:							
Notional debt amount ($200,000)	$—	$—	$—	$—	$—	$—	$513
Cap	3.00%	—	—	—	—	—	
Average fixed rate payable(3)	1.23%	—	—	—	—	—	
Variable rate receivable(4)	2.31%	—	—	—	—	—	

(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 September 30, 2018. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.
(2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves plus applicable margin at the reporting date. Excludes commitment fees related to the Facility and Corporate Revolver.
(3) We expect to pay the fixed rate if 1-month LIBOR is below the cap, and pay the market rate less the spread between the cap and the fixed rate if LIBOR is above the cap, net of the capped interest rate swaps.
(4) Based on implied forward rates in the yield curve at the reporting date.
(5) Represents the period October 1, 2018 through December 31, 2018.

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 September 30, 2018, our material off-balance sheet arrangements and transactions include operating leases and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Kosmos' liquidity or availability of or requirements for capital resources.

Critical Accounting Policies

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 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. 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, 2017.

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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 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, to us;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil and natural gas prices;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling and production risks and other operational and environmental risks and hazards;
- current and future government regulation of the oil and gas industry or regulation of the investment in or ability to do business with certain countries or regimes;
- cost of compliance with laws and regulations;
- changes in environmental, health and safety or climate change or greenhouse gas ("GHG") laws and regulations or the implementation, or interpretation, of those laws and regulations;
- adverse effects of sovereign boundary disputes in the jurisdictions in which we operate;
- environmental liabilities;
- geological, geophysical and other technical and operations problems, including drilling and oil and gas production and processing;
- military operations, civil unrest, outbreaks of disease, terrorist acts, wars or embargoes;
- the cost and availability of adequate insurance coverage and whether such coverage is enough to sufficiently mitigate potential losses and whether our insurers comply with their obligations under our coverage agreements;
- our vulnerability to severe weather events;
- our ability to meet our obligations under the agreements governing our indebtedness;
- the availability and cost of financing and refinancing our indebtedness;
- the amount of collateral required to be posted from time to time in our hedging transactions, letters of credit and other secured debt;

- the result of any legal proceedings, arbitrations, or investigations we may be subject to or involved in;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the "Item 1A. Risk Factors" section of this 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 a to identify estimates and forward-looking statements. Estimates and forward-looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward-looking statement because of new information, future events or other factors. Estimates and forward-looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward-looking statements discussed in this quarterly report on Form 10-Q might

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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 nine months ended September 30, 2018:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
	(In thousands)		
Fair value of contracts outstanding as of December 31, 2017	$ (97,036)	$ 1,017	$ (96,019)
Acquisition and novation of DGE contracts	(41,139)	—	(41,139)
Changes in contract fair value	(232,523)	466	(232,057)
Contract maturities	103,675	(970)	102,705
Fair value of contracts outstanding as of September 30, 2018	$ (267,023)	$ 513	$ (266,510)

Commodity Price Risk

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

Commodity Derivative Instruments

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

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Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of September 30, 2018. Volumes and weighted average prices are net of any offsetting derivatives entered into.

				Weighted Average Price per Bbl						Asset (Liability) Fair Value at September 30,
				Net Deferred Premium						
Term	Type of Contract	Index	MBbl	Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling	Call	2018(2)
										(In thousands)
2018:										
Oct — Dec	Swap with puts	Dated Brent	1,500	$—	$56.75	$43.33	$—	$—	$ —	$(36,530)
Oct — Dec	Three-way collars	Dated Brent	733	0.74	—	41.57	56.57	65.91	—	(12,398)
Oct — Dec	Four-way collars	Dated Brent	751	1.06	—	40.00	50.00	61.33	70.00	(6,818)
Oct — Dec	Sold calls(1)	Dated Brent	503	—	—	—	—	65.00	—	(8,213)
Oct — Dec	Purchased Calls	Dated Brent	500	1.88	—	—	—	—	70.00	5,052
Oct — Dec	Purchased Puts	NYMEX WTI	141	2.70	—	—	53.00	—	—	(360)
Oct — Dec	Collars	NYMEX WTI	35	—	—	—	62.29	66.35	—	(233)
Oct — Dec	Swaps	NYMEX WTI	698	—	54.69	—	—	—	—	(11,638)
2019:										
Jan — Dec	Three-way collars	Dated Brent	10,500	$1.17	$—	$43.81	$53.33	$73.58	$ —	$(105,522)
Jan — Dec	Sold calls(1)	Dated Brent	913	—	—	—	—	80.00	—	(5,112)
Jan — Dec	Swaps	NYMEX WTI	1,747	—	52.31	—	—	—	—	(31,755)
Jan — Jun	Collars	NYMEX WTI	339	—	—	—	57.77	63.70	—	(2,988)
Jan — Dec	Collars	Argus LLS	1,000	—	—	—	60.00	88.75	—	(429)
2020:										
Jan — Dec	Three-way collars	Dated Brent	2,000	$—	$—	$50.00	$60.00	$90.54	$ —	$(2,985)
Jan — Dec	Sold calls(1)	Dated Brent	8,000	—	—	—	—	80.00	—	(47,093)

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.
(2) Fair values are based on the average forward oil prices on September 30, 2018.

At September 30, 2018, our open commodity derivative instruments were in a net liability position of $267.0 million. As of September 30, 2018, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $145.4 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $127.1 million.

Interest Rate Derivative Instruments

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" section of our annual report on Form 10-K for specific information regarding the terms of our interest rate derivative instruments that are sensitive to changes in interest rates.

Interest Rate Sensitivity

At September 30, 2018, we had indebtedness outstanding under the Facility of $1,325.0 million and the Corporate Revolver of $300 million, of which $1,425.0 million bore interest at floating rates after consideration of our fixed rate interest rate hedges. The interest rate on this indebtedness as of September 30, 2018 was approximately 5.6%. If LIBOR increased by 10% at this level of floating rate debt, we would pay an additional $2.9 million in interest expense per year on the Facility. We pay commitment fees on the undrawn availability and unavailable commitments under the Facility and on the undrawn availability under the Corporate Revolver, which are not subject to changes in interest rates.

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As of September 30, 2018, the fair market value of our interest rate swaps was a net asset of approximately $0.5 million. If LIBOR changed by 10%, it would have a negligible impact on the fair market value of our interest rate swaps.

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 September 30, 2018, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, including that such information is accumulated and communicated to the Company’s management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

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.

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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.

In June 2016, Kosmos Energy Ghana HC filed a Request for Arbitration with the International Chamber of Commerce ("ICC") against Tullow Ghana Limited in connection with a dispute arising under the DT Joint Operating Agreement. At dispute was Kosmos Energy Ghana HC’s responsibility for expenditures arising from Tullow Ghana Limited’s contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow sought to charge such expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputed that these expenditures were chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement and that the Seadrill West Leo drilling rig contract had not been entered into in connection with joint operations.

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

Item 1A. Risk Factors

Other than with respect to the risk factors set forth below, 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, 2017.

Our operations in the U.S. Gulf of Mexico may be materially adversely affected by tropical storms and hurricanes.

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

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

In the U.S. Gulf of Mexico, there have been a series of regulatory initiatives developed and implemented at the federal level to address the direct impact of the incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through the present, the Department of Interior (“DOI”) through the Bureau of Ocean Energy Management (“BOEM”) and the Bureau of Safety and Environmental Enforcement (“BSEE”), has issued a variety of regulations and Notices to Lessees and Operators (“NTLs”), intended to impose additional safety, permitting and certification requirements applicable to exploration, development and production activities in the U.S. Gulf of Mexico. These regulatory initiatives effectively slowed down the pace of drilling and production operations in the U.S. Gulf of Mexico as adjustments were being made in operating procedures, certification requirements and lead times for inspections, drilling applications and permits, and exploration and production plan reviews, and as the federal agencies evolved into their present day bureaus. On April 17, 2015, BSEE published a proposed rule that would impose more stringent standards on blowout preventers (“BOP”). In April 2016, BSEE issued a final version of this rule effective July 2016, though some requirements of the rule have delayed compliance deadlines. The final rule addresses the full range of systems and equipment associated with well control operations, focusing on requirements for BOPs, well design, well control casing, cementing, real-time monitoring and subsea containment. Key features of the well control regulations include requirements for BOPs, double shear rams, third-party reviews of equipment, real time monitoring data, safe drilling margins, centralizers, inspections and other reforms related to well design and control, casing, cementing and subsea containment. On March 28, 2017, President Trump signed an executive order (the “March 2017 Executive Order”) directing federal agencies to initiate rulemakings to suspend, revise or rescind certain regulations relating to the energy industry as necessary to ensure

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consistency with the goals of energy independence, economic growth and cost-effective environmental regulation. In response to the March 2017 Executive Order and a subsequent executive order issued by President Trump in April 2017 focusing on offshore energy development, in May 2018, BSEE published a proposal to relax certain requirements of the July 2016 rule. The proposed rule's comment period expired on August 6, 2018, but a final rule has not yet been published; this rule is likely to be subject to legal challenges.

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

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

Issuer Purchases of Equity Securities

Under the terms of our Long Term Incentive Plan ("LTIP"), we have issued restricted shares to our employees. On the date that these restricted shares vest, we provide such employees the option to sell shares to cover their tax liability, via a net exercise provision pursuant to our applicable restricted share award agreements and the LTIP, at either the number of vested shares (based on the closing price of our common shares on such vesting date) equal to the minimum statutorily tax liability owed by such grantee or up to the maximum statutory tax liability for such grantee. The Company may repurchase the restricted shares sold by the grantees to settle their tax liability. The repurchased shares are reallocated to the number of shares available for issuance under the LTIP. The following table outlines the total number of shares purchased during the nine months ended September 30, 2018 and the average price paid per share.

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

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

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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, other than as follows:

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

Under the Iran Threat Reduction and Syria Human Rights Act of 2012, which added Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our “affiliates” (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities during the period covered by the report. Because the Securities and Exchange Commission (“SEC”) defines the term “affiliate” broadly, it includes any entity controlled by us as well as any person or entity that controls us or is under common control with us (“control” is also construed broadly by the SEC).

We are not presently aware that we and our consolidated subsidiaries have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the fiscal quarter ended September 30, 2018. In addition, except as described below, at the time of filing this quarterly report on Form 10-Q, we are not aware of any such reportable transactions or dealings by companies that may be considered our affiliates as to whether they have knowingly engaged in any such reportable transactions or dealings during such period. Upon the filing of periodic reports by such other companies for the fiscal quarter or fiscal year ended September 30, 2018, as the case may be, additional reportable transactions may be disclosed by such companies.

As of September 30, 2018, funds affiliated with Warburg Pincus (“Warburg Pincus”) held approximately 20% of our outstanding common shares. We are also a party to a shareholders agreement with Warburg Pincus pursuant to which, among other things, Warburg Pincus currently has the right to designate one member of our board of directors. Accordingly, Warburg Pincus may be deemed an “affiliate” of us, both currently and during the fiscal quarter ended September 30, 2018.

Disclosure relating to Warburg Pincus and its affiliates

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

EIGI Disclosure:

Quarter ended September 30, 2018

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

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.

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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	November 5, 2018	/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
10.1	Securities Purchase Agreement by and among DGE Group Series Holdco, LLC, and each of its three designated series, DGE Group Series Holdco, LLC, Series I, DGE Group Series Holdco, LLC, Series, II, DGE Group Series Holdco, LLC, Series III, and Kosmos Energy Gulf of Mexico, LLC dated August 3, 2018.
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