Kosmos Energy Ltd.
Form 10-Q
August 06, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2012

o 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 x No o

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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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

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 July 31, 2012**
Common Shares, $0.01 par value	389,201,453

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GLOSSARY AND SELECT ABBREVIATIONS

The following are abbreviations and definitions of certain terms 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.
Developed acreage	The number of acres that are allocated or assignable to productive wells or wells capable of production.
Development	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.
Dry hole	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
E&P	Exploration and production.
FASB	Financial Accounting Standards Board.
Farm-in	An agreement whereby an oil company acquires a portion of the working interest in a block from the owner of such interest, usually in return for cash and for taking on a portion of the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment.
FPSO	Floating production, storage and offloading vessel.
MBbl	Thousand barrels of oil.
Mcf	Thousand cubic feet of natural gas.
Mcfpd	Thousand cubic feet per day of natural gas.
MMBbl	Million barrels of oil.
MMBoe	Million barrels of oil equivalent.
MMcf	Million cubic feet of natural gas.
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 minerals gives an E&P company temporary and limited rights, including an exclusive option, to explore for, develop, and produce minerals 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 from the area in which it was formed to a reservoir rock where it can accumulate.
Plan of development or *PoD*	A written document outlining the steps to be undertaken to develop a field.
Productive well	An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

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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 them fail neither oil nor natural gas will 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	Proved developed reserves are those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.
Proved undeveloped reserves	Proved undeveloped reserves are 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.
Structural trap	A structural strap is a topographic feature in the earth s subsurface that forms a high point in the rock strata. This facilitates the accumulation of oil and gas in the strata.
Structural-stratigraphic trap	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.
Stratigraphy	The study of the composition, relative ages and distribution of layers of sedimentary rock.
Stratigraphic trap	A stratigraphic trap is formed from a change in the character of the rock rather than faulting or folding of the rock and oil is held in place by changes in the porosity and permeability of overlying rocks.
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)

	June 30, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 629,951	$ 673,092
Restricted cash	22,954	23,747
Receivables:		
Joint interest billings	139,798	199,699
Oil sales		109,475
Other	22,529	981
Inventories	50,426	27,101
Prepaid expenses and other	15,257	13,913
Current deferred tax assets	56,281	64,473
Derivatives	1,512	
Total current assets	938,708	1,112,481
Property and equipment:		
Oil and gas properties, net of accumulated depletion of $213,040 and $135,622, respectively	1,444,350	1,367,265
Other property, net of accumulated depreciation of $10,021 and $8,068, respectively	15,562	9,776
Property and equipment, net	1,459,912	1,377,041
Other assets:		
Restricted cash	3,800	3,800
Deferred financing costs and other assets, net of accumulated amortization of $10,970 and $6,582, respectively	51,713	54,847
Long-term deferred tax assets	7,520	3,765
Total assets	$ 2,461,653	$ 2,551,934
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable	$ 194,808	$ 278,006
Accrued liabilities	31,346	37,194
Derivatives	21,910	24,407
Total current liabilities	248,064	339,607
Long-term liabilities:		
Long-term debt	1,110,000	1,110,000
Derivatives	4,941	8,427
Asset retirement obligations	21,992	20,670
Deferred tax liability	76,618	47,608
Other long-term liabilities	10,795	4,896
Total long-term liabilities	1,224,346	1,191,601
Shareholders equity:		

Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at June 30, 2012 and December 31, 2011				
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 391,411,703 and 390,530,946 issued at June 30, 2012 and December 31, 2011, respectively		3,914		3,905
Additional paid-in capital		1,668,302		1,629,453
Accumulated deficit		(678,532)		(616,148)
Accumulated other comprehensive income		3,950		3,522
Treasury stock, at cost, 2,171,410 and 649,818 shares at June 30, 2012 and December 31, 2011, respectively		(8,391)		(6)
Total shareholders equity		989,243		1,020,726
Total liabilities and shareholders equity	$	2,461,653	$	2,551,934

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Revenues and other income:				
Oil and gas revenue	$ 112,214	$ 124,083	$ 227,985	$ 216,652
Interest income	282	2,613	1,028	4,967
Other income	175	157	205	644
Total revenues and other income	112,671	126,853	229,218	222,263
Costs and expenses:				
Oil and gas production	19,592	14,301	26,918	34,296
Exploration expenses	16,901	85,220	56,545	93,652
General and administrative	34,799	19,760	74,122	33,047
Depletion and depreciation	32,999	22,869	64,648	46,367
Amortization - deferred financing costs	2,194	2,194	4,388	11,805
Interest expense	10,446	18,400	23,504	38,658
Derivatives, net	(1,982)	1,363	1,878	10,234
Loss on extinguishment of debt				59,643
Doubtful accounts expense		(39,782)		(39,782)
Other expenses, net	44	84	792	61
Total costs and expenses	114,993	124,409	252,795	287,981
Income (loss) before income taxes	(2,322)	2,444	(23,577)	(65,718)
Income tax expense (benefit)	22,521	11,535	38,807	(1,976)
Net loss	(24,843)	(9,091)	(62,384)	(63,742)
Accretion to redemption value of convertible preferred units		(7,595)		(24,442)
Net loss attributable to common shareholders/unit holders	$ (24,843)	$ (16,686)	$ (62,384)	$ (88,184)
Net loss per share attributable to common shareholders:				
Basic	$ (0.07)		$ (0.17)	
Diluted	$ (0.07)		$ (0.17)	
Pro forma basic		$ (0.03)		$ (0.19)
Pro forma diluted		$ (0.03)		$ (0.19)
Weighted average number of shares used to compute net loss per share:				
Basic	370,720		369,973	
Diluted	370,720		369,973	

Pro forma basic	348,820	340,030
Pro forma diluted	348,820	340,030

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(In thousands)

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net loss	$ (24,843)	$ (9,091)	$ (62,384)	$ (63,742)
Other comprehensive income:				
Reclassification adjustments for derivative losses included in net loss	214	283	428	1,741
Income tax benefit				
Other comprehensive income	214	283	428	1,741
Comprehensive loss	$ (24,629)	$ (8,808)	$ (61,956)	$ (62,001)

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

(In thousands)

(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Accumulated Other Comprehensive	Treasury	
	Shares	Amount	Capital	Deficit	Income	Stock	Total
Balance as of December 31, 2011	390,531	$ 3,905	$ 1,629,453	$ (616,148)	$ 3,522	$ (6)	$ 1,020,726
Equity-based compensation			38,851				38,851
Derivatives, net					428		428
Restricted stock awards	881	9	(9)				
Restricted stock forfeitures			7			(7)	
Purchase of treasury stock						(8,378)	(8,378)
Net loss				(62,384)			(62,384)
Balance as of June 30, 2012	391,412	$ 3,914	$ 1,668,302	$ (678,532)	$ 3,950	$ (8,391)	$ 989,243

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating activities		
Net loss	$ (62,384)	$ (63,742)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	69,036	58,172
Deferred income taxes	33,447	(2,291)
Unsuccessful well costs	19,237	83,317
Derivative related activity	(7,067)	14,518
Equity-based compensation	38,851	9,120
Doubtful accounts expense		(39,782)
Loss on extinguishment of debt		59,643
Other	4,983	1,023
Changes in assets and liabilities:		
Decrease in receivables	155,884	11,145
(Increase) decrease in inventories	(14,075)	547
Increase in prepaid expenses and other	(1,344)	(8,745)
Decrease in accounts payable	(66,536)	(47,728)
Decrease in accrued liabilities	(9,347)	(20,698)
Net cash provided by operating activities	160,685	54,499
Investing activities		
Oil and gas assets	(188,075)	(206,763)
Other property	(6,912)	(847)
Notes receivable		3,781
Restricted cash	793	84,286
Net cash used in investing activities	(194,194)	(119,543)
Financing activities		
Borrowings under long-term debt		1,393,000
Payments on long-term debt		(1,138,000)
Net proceeds from the initial public offering		580,374
Purchase of treasury stock	(8,378)	
Deferred financing costs	(1,254)	(52,466)
Net cash provided by (used in) financing activities	(9,632)	782,908
Net increase (decrease) in cash and cash equivalents	(43,141)	717,864
Cash and cash equivalents at beginning of period	673,092	100,415
Cash and cash equivalents at end of period	$ 629,951	$ 818,279
Supplemental cash flow information		
Cash paid for:		
Interest	$ 21,339	$ 33,828

Income taxes	$	16,620	$	725

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 March 5, 2004. As a holding company, Kosmos Energy Ltd. s management operations are conducted through a wholly owned subsidiary, Kosmos Energy, LLC. The terms Kosmos, the Company, we, us, our, ours, and similar terms when used in the present tense or prospectively or for historical periods since May 16, 2011 r to Kosmos Energy Ltd. and its wholly owned subsidiaries and for historical periods prior to May 16, 2011 refer to Kosmos Energy Holdings and its wholly owned subsidiaries, unless the context indicates otherwise.

We are an independent oil and gas exploration and production company currently focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production, discoveries and exploration prospects offshore Ghana, as well as petroleum contracts offshore Mauritania, Morocco and Suriname and onshore Cameroon. Kosmos Energy Ltd. transitioned from its development stage to operational activities in January 2011. Accordingly, reporting as a development stage company is no longer deemed necessary.

We have one business segment, which is the exploration and production of oil and natural gas.

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 June 30, 2012, the consolidated results of operations for the three and six months ended June 30, 2012 and 2011, and consolidated cash flows for the six months ended June 30, 2012 and 2011. During the three months ended June 30, 2012, we corrected an immaterial error in our financial statements by capitalizing $3.0 million which was previously recorded as exploration expense during the three months ended March 31, 2012. 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. 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, 2011, included in our annual report on Form 10-K.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Kosmos Energy Ltd. and its wholly owned subsidiaries. All intercompany transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

Cash and Cash Equivalents

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

Restricted Cash

In accordance with our commercial debt facility, we are required to maintain a balance that is sufficient to meet the payment of interest and fees for the next six-month period. As of June 30, 2012 and December 31, 2011, we had $23.0 million and $23.7 million, respectively, in current restricted cash to meet this requirement. Additionally as of June 30, 2012 and December 31, 2011, we had $3.8 million of long-term restricted cash used to cash collateralize performance guarantees related to our petroleum agreements. See Note 18 Subsequent Events.

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Receivables

Our receivables consist of joint interest billings, oil sales and other receivables for which the Company generally does not require collateral security. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of time past due, future net revenues of the debtor s ownership interest in oil and natural gas properties we operate, and the owner s ability to pay its obligation, among other things. We did not have any allowances for doubtful accounts as of June 30, 2012 and December 31, 2011.

Inventories

Inventories consisted of $27.7 million and $26.9 million of materials and supplies and $22.7 million and $0.2 million of hydrocarbons as of June 30, 2012 and December 31, 2011, 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 market.

Hydrocarbon inventory is carried at the lower of cost, using the weighted average cost method, or market. Hydrocarbon inventory costs include expenditures and other charges (including depletion) directly and indirectly incurred in bringing the inventory to its existing condition. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory costs.

Exploration and Development Costs

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

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

Depletion, Depreciation and Amortization

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

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

	Years Depreciated
Leasehold improvements	6 to 8
Office furniture, fixtures and computer equipment	3 to 7
Vehicles	5

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

Capitalized Interest

Interest costs from external borrowings are capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

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Asset Retirement Obligations

The Company accounts for asset retirement obligations as required by ASC 410 Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset s acquisition date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion and depreciation in the consolidated statement of operations.

Variable Interest Entity

A variable interest entity (VIE), as defined by ASC 810 Consolidation, is an entity that by design has insufficient equity to permit it to finance its activities without additional subordinated financial support or equity holders that lack the characteristics of a controlling financial interest. VIEs are consolidated by the primary beneficiary, which is the entity that has the power to direct the activities of the VIE that most significantly impact the VIE s performance and will absorb losses or receive benefits from the VIE that could potentially be significant to the VIE.

Our wholly owned subsidiary, Kosmos Energy Finance International, meets the definition of a VIE. The Company is the primary beneficiary of this VIE, which is consolidated in these financial statements.

Prior to the incorporation of Kosmos Energy Finance International on March 18, 2011, Kosmos Energy Finance International did not have any financial statement activity. Kosmos Energy Finance International s assets and liabilities are shown separately on the face of the consolidated balance sheet as of June 30, 2012, and December 31, 2011, in the following line items: current restricted cash; current derivatives assets; deferred financing costs and other assets; long-term debt; and current and long-term derivatives liabilities. At June 30, 2012, Kosmos Energy Finance International had $229.6 million in cash and cash equivalents, $1.0 million in accrued liabilities and $6.1 million in other long-term liabilities. At December 31, 2011, Kosmos Energy Finance International had $231.6 million in cash and cash equivalents, $0.1 million in other receivables, $54.8 million in deferred financing costs and other assets, $1.2 million in accrued liabilities and $3.0 million in other long-term liabilities.

Impairment of Long-lived Assets

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

Derivative Instruments and Hedging Activities

We utilize oil derivative contracts to mitigate our exposure to commodity price risk associated with our anticipated future oil production. These derivative contracts consist of purchased puts and swaps with calls. We also use interest rate swap contracts to mitigate our exposure to interest rate fluctuations related to our long-term debt. Our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We do not apply hedge accounting to our oil derivative contracts. Effective June 1, 2010, we discontinued hedge accounting on our interest rate swap contracts. Therefore, from that date forward, the changes in the fair value of the instruments are recognized in earnings during the period of change. See Note 10 Derivative Financial Instruments.

Estimates of Proved Oil and Natural Gas Reserves

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with

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guidelines established by the Securities and Exchange Commission (SEC) and the FASB. The accuracy of these reserve estimates is a function of:

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

Revenue Recognition

We 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.

Stock-based Compensation

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

Treasury Stock

We record treasury stock purchases at cost. All of our treasury stock purchases are from our employees that surrendered shares to the Company to satisfy their minimum tax withholding requirements and were not part of a formal stock repurchase plan. Additionally, treasury stock includes forfeited restricted stock awards granted under our long-term incentive plan.

Income Taxes

The Company accounts for income taxes as required by ASC 740 Income Taxes. Under this method, deferred income taxes are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts expected to be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. See Note 15 Income Taxes.

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

Foreign Currency Translation

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

Concentration of Credit Risk

There are a variety of factors which affect the market for oil, including the proximity and capacity of transportation facilities, demand for oil, the marketing of competitive fuels and the effects of government regulations on oil production and sales. Our revenue can be materially affected by current economic conditions and the price of oil. However, based on the current demand for crude oil and the fact that alternative purchasers are readily available, we believe that the loss of our marketing agent and/or any of the purchasers identified by our marketing agent would not have a long-term material adverse effect on our financial position or results of operations. We have required our marketing agent to post a letter of credit covering the estimated proceeds from our revenue transactions, until such proceeds are received.

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Recent Accounting Standards

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities, to improve reporting and transparency of offsetting (netting) assets and liabilities and the related effects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

3. Acquisition of FPSO

Effective May 7, 2010, Tullow Ghana Limited, a subsidiary of Tullow Oil plc, (Tullow) as Unit Operator for and on behalf of the Jubilee Unit partners under the Unitization and Unit Operating Agreement (Jubilee UUOA), entered into the Advance Payments Agreement with MODEC, Inc. (MODEC) related to partial funding of the construction of the FPSO. The maturity date of the Advance Payments Agreement was extended from September 15, 2011 through the acquisition date of the FPSO.

On December 29, 2011, Tullow as Unit Operator for and on behalf of the Jubilee Unit partners under the Jubilee UUOA, acquired the FPSO we are using to produce hydrocarbons from the Jubilee Field from MODEC for $754.5 million, or $202.6 million net to Kosmos. At the time of the acquisition of the FPSO, our note receivable under the Advance Payments Agreement was $102.8 million. To fund the purchase, we paid $99.8 million in cash and applied the note receivable due under the Advance Payments Agreement to the purchase. As of December 31, 2011 the remaining balance under the Advance Payments Agreement was zero. The acquisition was recorded as an increase to oil and gas property. Prior to the acquisition of the FPSO, the Jubilee Unit leased the FPSO from MODEC. The lease costs were recorded as oil and gas production costs.

4. Jubilee Field Unitization

The Jubilee Field in Ghana, discovered by the Mahogany-1 well in June 2007, covers an area within both the West Cape Three Points (WCTP) and Deepwater Tano (DT) Blocks. Consistent with the Ghanaian Petroleum Law, the WCTP and DT Petroleum Agreements (PAs) and as required by Ghana s Ministry of Energy, it was agreed the Jubilee Field would be unitized for optimal resource recovery. Kosmos and its partners negotiated a comprehensive unit operating agreement, the Jubilee UUOA, to unitize the Jubilee Field and govern each party s respective rights and duties in the Jubilee Unit. On July 13, 2009, the Ministry of Energy provided its written approval of the Jubilee UUOA. The Jubilee UUOA was executed by all parties and was effective July 16, 2009. The tract participations were 50% for each block. Tullow is the Unit Operator, and Kosmos is the Technical Operator for the development of the Jubilee Field. Pursuant to the terms of the Jubilee UUOA, the track participations are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. Any party to the Jubilee UUOA with more than a 10% Unit Interest (participating interest in the Jubilee Unit) may call for a second redetermination after December 1, 2013. As a result of the initial redetermination process, the tract participation was determined to be 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest was increased from 23.50868% (our percentage after Tullow s acquisition of EO Group Limited (EO Group) see Note 5 Joint Interest Billings) to 24.07710%. The consolidated financial statements are based on these re-determined tract participations. As a result of the change in our Unit Interest, we recorded increases in joint interest billings receivables, oil and gas properties, notes receivable, inventories, oil and gas production expenses and general and administrative expenses of $67.6 million, $22.1 million, $2.5 million, $0.4 million, $1.6 million and $0.6 million, respectively, and an increase of $94.9 million in accounts payable as of December 31, 2011. Our capital costs related to the increased Unit Interest is expected to be paid during 2012. Although the Jubilee Field is unitized, Kosmos working interest in each block outside the boundary of the Jubilee Unit area did not change. Kosmos remains operator of the WCTP Block outside the Jubilee Unit area.

5. Joint Interest Billings

The Company s joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company. Joint interest billings are classified on the face of the consolidated balance sheets as current or long-term receivables based on when collection is expected to occur. As of June 30, 2012 and December 31, 2011, we had $139.8 million and $199.7 million, respectively, included in current joint interest billings receivable. There were no long-term joint interest billings as of June 30, 2012 and December 31, 2011.

EO Group s share of costs under the WCTP PA incurred attributable to its WCTP Block interest were paid by Kosmos until first production. EO Group was required to reimburse Kosmos for all development costs paid on EO Group s behalf upon commencement of production in 2010.

On July 22, 2011, Tullow acquired EO Group s entire 3.5% interest in the WCTP PA, including the correlative interest in the Jubilee Unit. As a result of the transaction, we received full repayment of the long-term joint interest billing receivable related to Jubilee Field development costs we paid on EO Group s behalf. The related valuation allowance of $39.8 million was reversed during the second quarter of 2011. In addition, our participation interest in the Jubilee Unit increased 0.01738%. This resulted from the

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elimination of EO Group s carry by the other Jubilee owners of GNPC s additional paying interest of 3.75% in the Jubilee Unit. Our working interest in the remainder of the WCTP Block was not changed by the transaction and remains 30.875% (before giving effect to GNPC s optional additional paying interest).

6. Property and Equipment

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

	June 30, 2012	December 31, 2011
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 666,337	$ 607,338
Unproved properties	381,400	294,701
Support equipment and facilities	609,653	600,848
Total oil and gas properties	1,657,390	1,502,887
Less: accumulated depletion	(213,040)	(135,622)
Oil and gas properties, net	1,444,350	1,367,265
Other property, net	15,562	9,776
Property and equipment, net	$ 1,459,912	S 1,377,041

We recorded depletion expense of $31.2 million and $21.7 million for the three months ended June 30, 2012 and 2011, respectively, and $61.3 million and $44.1 million for the six months ended June 30, 2012 and 2011, respectively. The Company had depletion costs of $16.1 million and nil included in crude oil inventory and other receivables as of June 30, 2012 and December 31, 2011, respectively.

7. Suspended Well Costs

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

The following table reflects the Company s capitalized exploratory well costs on completed wells as of and during the six months ended June 30, 2012. The table excludes $16.6 million in costs that were capitalized and subsequently expensed in the same period.

	June 30, 2012
	(In thousands)
Beginning balance (January 1, 2012)	$ 267,592

Additions to capitalized exploratory well costs pending the determination of proved reserves		66,789
Reclassification due to determination of proved reserves		
Capitalized exploratory well costs charged to expense		(2,627)
Ending balance (June 30, 2012)	$	331,754

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

		June 30, 2012		December 31, 2011
		(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$	127,155	$	132,838
Exploratory well costs capitalized for a period one to three years		204,599		134,754
Ending balance	$	331,754	$	267,592
Number of projects with exploratory well costs that have been capitalized for more than one year		6		3

As of June 30, 2012, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Mahogany Area (formerly known as the Mahogany East Area), Teak-1 and Teak-2 discoveries in the WCTP Block and the Tweneboa, Enyenra and Ntomme discoveries in the DT Block.

Mahogany Area The Mahogany area, a combined area covering parts of the Mahogany discovery and the Mahogany Deep discovery area was declared commercial in September 2010, and a PoD was submitted to Ghana s Ministry of Energy as of May 2,

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2011. In a letter dated May 16, 2011, the Ministry of Energy did not approve the PoD and requested that the WCTP Block partners take certain steps regarding notifications of discovery and commerciality; and requested other information. The WCTP Block partners believe the combined submission was proper and have held meetings with GNPC which resolved issues relating to the PoD work program. From May 2011, GNPC and the WCTP Block partners continued working to resolve other differences; however, the WCTP PA contains specific timelines for PoD approval and discussions, which expired at the end of June 2011. On June 30, 2011, we, as Operator of the WCTP Block and on behalf of the WCTP Block partners, delivered a Notice of Dispute to the Ministry of Energy as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government of Ghana regarding approval of the Mahogany PoD. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter of approval of the PoD. We and the WCTP Block partners continue discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

Teak-1 Discovery Two appraisal wells have been drilled. Following additional appraisal and evaluation, a decision regarding commerciality of the Teak-1 discovery is expected to be made by the WCTP Block partners in 2013. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana s Ministry of Energy, as required under the WCTP PA.

Teak-2 Discovery We have performed a gauge installation on the well and are reprocessing seismic data. Following appraisal and evaluation, a decision regarding commerciality of the Teak-2 discovery is expected to be made by the WCTP Block partners in 2013. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana s Ministry of Energy, as required under the WCTP PA.

Ntomme Discovery One appraisal well has been drilled. Following additional appraisal and evaluation, a decision regarding commerciality of the Ntomme discovery is expected to be made by the DT Block partners by the end of 2012. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana s Ministry of Energy, as required under the DT PA.

Tweneboa Discovery Three appraisal wells have been drilled. Following additional appraisal and evaluation, a decision regarding commerciality of the Tweneboa discovery is expected to be made by the DT Block partners by January 2013. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana s Ministry of Energy, as required under the DT PA. However, the DT Block partners have the option to request a new petroleum agreement for the Tweneboa discovery area, thereby extending the period of commercial assessment of the discovery.

Enyenra Discovery Four appraisal wells have been drilled. Following additional appraisal and evaluation, a decision regarding commerciality of the Enyenra discovery is expected to be made by the DT Block partners by the end of 2012. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana s Ministry of Energy, as required under the DT PA.

8. Accounts Payable and Accrued Liabilities

At June 30, 2012 and December 31, 2011, $194.8 million and $278.0 million, respectively, were recorded for invoices received but not paid. Accrued liabilities were $31.3 million and $37.2 million at June 30, 2012 and December 31, 2011, respectively, and consisted of the following:

		June 30, 2012		December 31, 2011
		(In thousands)		
Accrued liabilities:				
Accrued exploration, development and production	$	20,352	$	27,666
Accrued general and administrative expenses		7,440		2,159
Accrued interest		986		1,208
Taxes other than income		2,532		1,095
Income taxes		36		5,066
	$	31,346	$	37,194

9. Debt

In March 2011, the Company secured a $2.0 billion commercial debt facility (the Facility) from a number of financial institutions and extinguished the then existing commercial debt facilities. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. The total loan commitments of the Facility may be increased up to a maximum of $3.0 billion if the lenders increase their commitments or if loan commitments from new financial institutions are added. The International Finance Corporation entered the Facility in February 2012. The terms and conditions of the Facility remained consistent with the original terms and conditions, and the total commitment under the Facility remained unchanged.

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As part of the debt refinancing in March 2011, we recorded a $59.6 million loss on the extinguishment of debt. Additionally, we have $61.3 million of deferred financing costs related to the Facility, which are being amortized over the term of the Facility.

As of June 30, 2012, borrowings under the Facility totaled $1.1 billion. As of June 30, 2012, the undrawn availability under the Facility was an additional $50.0 million. Interest expense was $7.9 million and $11.7 million (net of capitalized interest of $3.2 million and $0.8 million), and commitment fees were $1.6 million and $1.3 million for the three months ended June 30, 2012 and 2011, respectively. Interest expense was $18.4 million and $27.3 million (net of capitalized interest of $4.5 million and $2.0 million) and commitment fees were $3.3 million and $3.6 million for the six months ended June 30, 2012 and 2011, respectively.

The interest is the aggregate of the applicable margin (3.25% to 4.75%, depending on the amount of the Facility that is being utilized and the length of time that has passed from the date the Facility was entered into); LIBOR; and mandatory cost (if any, as defined in the Facility). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). Kosmos pays commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees for the lenders are equal to 40% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. The Company recognizes interest expense in accordance with ASC 835 Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of borrowings under the Facility. Accordingly, we recognized interest expense in excess of interest currently payable of $1.3 million and $1.2 million during the three months ended June 30, 2012 and 2011, respectively, and $3.1 million and $1.2 million during the six months ended June 30, 2012 and 2011, respectively.

The Facility provides a revolving-credit and letter of credit facility for an availability period that expires on May 15, 2014 (in the case of the revolving-credit facility) and on the final maturity date (in the case of the letter of credit facility), which is March 29, 2018. The available facility amount is subject to borrowing base constraints and also is constrained by the amortization schedule (once repayments under the Facility begin). As of May 15, 2014, outstanding borrowings will be subject to an amortization schedule. The first required payment could be as early as June 15, 2014, subject to the level of outstanding borrowings.

Kosmos has the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, was previously determined each year on June 15 and December 15 as part of a forecast that is prepared by and agreed to by Kosmos and the Technical and Modeling Banks; however, in April 2012, the lenders agreed to change the borrowing base determination dates to April 15 and October 15. The formula to calculate the borrowing base amount is based, in part, on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain ratios.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by us.

We were in compliance with the financial covenants contained in the Facility as of the April 19, 2012 forecast, which requires the maintenance of:

- the field life cover ratio, not less than 1.30x; and
- the loan life cover ratio, not less than 1.10x.

The field life cover ratio is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the depletion of the Jubilee Field plus the net present value of capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility. The loan life cover ratio is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the final maturity date of the Facility plus the net present value of capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility.

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At June 30, 2012, the scheduled maturities of debt during the five year period and thereafter are as follows:

	Payments Due by Year					
	2012 (1)	2013	2014	2015	2016	Thereafter
	(In thousands)					
Commercial debt facility(2)	$	$	$	$ 110,000	$ 444,444	$ 555,556

(1) Represents payments for the period July 1, 2012 through December 31, 2012.

(2) The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of June 30, 2012. Any increases or decreases in the level of borrowings or decreases in the available borrowing base would impact the scheduled maturities of debt during the five year period and thereafter.

10. 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 apply the provisions of ASC 815 Derivatives and Hedging, which require each derivative instrument to be recorded in the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. We do not apply hedge accounting treatment to our oil derivative contracts and, therefore, the changes in the fair values of these instruments are recognized in earnings in the period the change occurred. These fair value changes are shown in our statement of operations.

Effective June 1, 2010, we discontinued hedge accounting on all interest rate derivative instruments. Therefore, from that date forward, changes in the fair value of the instruments are recognized in earnings during the period of change. The effective portions of the discontinued hedges as of May 31, 2010, are included in accumulated other comprehensive income or loss (AOCI) in the equity section of the accompanying consolidated balance sheets, and are being transferred to earnings when the hedged transaction settles.

Oil Derivative Contracts

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 purchased puts and swaps with calls.

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

The following table sets forth the volumes in barrels underlying the Company s outstanding oil derivative contracts and the weighted average Dated Brent prices per Bbl for those contracts as of June 30, 2012. See Note 18 Subsequent Events.

			Weighted Average Price per Bbl			
Term	**Type of Contract**	**Bbls per day**	**Deferred Premium**	**Puts**	**Swaps**	**Calls**
2012:						
July - December	Purchased puts	4,739	$ 6.79	$ 61.56	$	$
August - December	Swaps with calls	6,536			97.21	110.00
2013 :						
January - December	Purchased puts	2,515	$ 7.32	$ 61.73	$	$

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Interest Rate Swaps Derivative Contracts

The following table summarizes our open interest rate swaps as of June 30, 2012:

Term		Weighted Average Notional Amount (In thousands)	Weighted Average Fixed Rate	Floating Rate
July 2012 December 2012	$	306,420	1.98%	6-month LIBOR
January 2013 December 2013	$	227,103	2.06%	6-month LIBOR
January 2014 December 2014	$	133,434	1.99%	6-month LIBOR
January 2015 December 2015	$	45,319	2.03%	6-month LIBOR
January 2016 June 2016	$	12,500	2.27%	6-month LIBOR

Effective June 1, 2010, the Company discontinued hedge accounting on all existing interest rate derivative instruments. Prior to June 1, 2010, any ineffectiveness on the interest rate swaps was immaterial; therefore, no amount was recorded in earnings for ineffectiveness. We have included an estimate of nonperformance risk in the fair value measurement of our interest rate derivative contracts as required by ASC 820 Fair Value Measurements and Disclosures.

The following tables disclose the Company s derivative instruments as of June 30, 2012 and December 31, 2011:

Type of Contract	Balance Sheet Location		Estimated Fair Value Asset (Liability) June 30, 2012		December 31, 2011
			(In thousands)		
Derivatives not designated as hedging instruments:					
Derivative asset:					
Commodity	Derivatives assets current	$	1,512	$	
Derivative liability:					
Commodity	Derivatives liabilities current(1)		(18,402)		(20,303)
Interest rate	Derivatives liabilities current		(3,508)		(4,104)
Commodity	Derivatives liabilities long-term		(1,585)		(4,457)
Interest rate	Derivatives liabilities long-term		(3,356)		(3,970)
Total derivatives not designated as hedging instruments		$	(25,339)	$	(32,834)

(1) Includes $9.2 million and $3.2 million, as of June 30, 2012 and December 31, 2011, of cash settlements made on our purchased puts and compound options which were settled in the month subsequent to period end.

	Amount of Gain/(Loss)	Amount of Gain/(Loss)

Type of Contract	Location of Gain/(Loss)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
		(In thousands)			
Derivatives in cash flow hedging relationships:					
Interest rate(1)	Interest expense	$ (214)	$ (283)	$ (428)	$ (1,741)
Total derivatives in cash flow hedging relationships		$ (214)	$ (283)	$ (428)	$ (1,741)
Derivatives not designated as hedging instruments:					
Commodity	Derivatives, net	$ 1,982	$ (1,363)	$ (1,878)	$ (10,234)
Interest rate	Interest expense	(725)	(5,085)	(1,435)	(6,012)
Total derivatives not designated as hedging instruments		$ 1,257	$ (6,448)	$ (3,313)	$ (16,246)

(1) Amounts were reclassified from AOCI into earnings.

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The fair value of the effective portion of the derivative contracts on May 31, 2010, is reflected in AOCI and is being transferred to interest expense over the remaining term of the contracts. In accordance with the mark-to-market method of accounting, the Company recognizes changes in fair values of its derivative contracts as gains or losses in earnings during the period in which they occur. The Company expects to reclassify $1.0 million of gains from AOCI to interest expense within the next 12 months. See Note 11 Fair Value Measurements for additional information regarding the Company s derivative instruments.

11. Fair Value Measurements

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

- Level 1 quoted prices for identical assets or liabilities in active markets.

- Level 2 quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs derived principally from or corroborated by observable market data by correlation or other means.

- Level 3 unobservable inputs for the asset or liability.

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following tables present the Company s assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2012 and December 31, 2011, for each fair value hierarchy level:

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In thousands)			
June 30, 2012				
Assets:				
Money market accounts	$ 332,787	$	$	$ 332,787

Commodity derivatives				1,512				1,512
Liabilities:								
Commodity derivatives				(19,987)				(19,987)
Interest rate derivatives				(6,864)				(6,864)
Total	$	332,787	$	(25,339)	$		$	307,448
December 31, 2011								
Assets:								
Money market accounts(1)	$	489,761	$		$		$	489,761
Liabilities:								
Commodity derivatives				(24,760)				(24,760)
Interest rate derivatives				(8,074)				(8,074)
Total	$	489,761	$	(32,834)	$		$	456,927

(1) As reported in our annual report on Form 10-K, the Level 1 fair value measurements excluded $27.5 million of restricted cash. The table above has been revised to properly include this amount.

All fair values have been adjusted for nonperformance risk resulting in a decrease of the commodity derivative liabilities of approximately $0.4 million and a decrease of the interest rate derivatives of approximately of $0.2 million as of June 30, 2012. When the accumulated net present value for all of the derivative contracts with a counterparty is in an asset position, the Company uses the

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counterparty s credit default swap (CDS) rates to estimate non-performance risk. When the accumulated net present value for all derivative contracts for a counterparty are in a liability position, we use our internal rate of borrowing to estimate our non-performance risk.

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. The carrying values of our debt approximates fair value since they are subject to short-term floating interest rates that approximate the rates available to us for those periods. Our long-term receivables after any allowances for doubtful accounts approximate fair value. The estimates of fair value of these items are based on Level 2 inputs.

Commodity Derivatives

Our commodity derivatives represent crude oil purchased puts and swaps with calls for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to the our oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for Dated Brent, (iii) a credit-adjusted yield curve applicable to each counterparty by reference to the CDS market and (iv) an independently sourced estimate of volatility for Dated Brent. The volatility estimate was provided by certain independent brokers who are active in buying and selling oil options and was corroborated by market-quoted volatility factors. The deferred premium is included in the fair market value of the puts and compound options. See Note 10 Derivative Financial Instruments for additional information regarding the Company s derivative instruments.

Interest Rate Derivatives

As of June 30, 2012, the Company had interest rate swaps with notional amounts of $306.4 million, whereby the Company pays a fixed rate of interest and the counterparty pays a variable LIBOR-based rate. 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.

12. Asset Retirement Obligations

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

	June 30, 2012 (In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$	20,670
Liabilities incurred during period		
Revisions in estimated retirement obligations		
Liabilities settled during period		

Accretion expense		1,322
Ending asset retirement obligations	$	21,992

The Ghanaian legal and regulatory regime regarding oil field abandonment and other environmental matters is evolving. Currently, no Ghanaian environmental regulations expressly require that companies abandon or remove offshore assets although under international industry standards we would do so. The Petroleum Law provides for restoration that includes removal of property and abandonment of wells, but further states the manner of such removal and abandonment will be as provided in the Regulations; however, such Regulations have not been promulgated. Under the Environmental Permit for the Jubilee Field, a decommissioning plan will be prepared and submitted to the Ghana Environmental Protection Agency. ASC 410 Asset Retirement and Environmental Obligations requires the Company to recognize this liability in the period in which the liability was incurred. We have recorded an asset retirement obligation for fields that have commenced production, including wells in progress in such fields. Additional asset retirement obligations will be recorded in the period in which wells within such producing fields are commissioned.

13. Convertible Preferred Units

In May 2011, contemporaneous with Kosmos Energy Ltd. s IPO, the Series A Convertible Preferred Units (Series A Units), Series B Convertible Preferred Units (Series B Units) and Series C Convertible Preferred Units (Series C Units) of Kosmos Energy Holdings were exchanged into our common shares based on the pre-offering equity value of such interests. This resulted in the Series A Units, Series B Units and Series C Units being exchanged into 163.1 million; 109.8 million; and 4.8 million common shares of Kosmos Energy Ltd., respectively, or 277.7 million common shares in the aggregate. The common shares have one vote per share and a par value of $0.01. The exchange of the Convertible Preferred Units had the effect of increasing the book value of shareholders equity by approximately $1.0 billion. Accretion to redemption value of the Convertible Preferred Units was recorded

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through the date of the exchange. After the date of the exchange, the related accretion on the Convertible Preferred Units ceased to accrue and all rights of the holders with respect to the Convertible Preferred Units terminated, except for the right to receive shares of common shares issuable upon the exchange and the rights entitled to a holder of a common share.

The Convertible Preferred Units were issued in separate series at an issue price of $10 per unit, $25 per unit, and $28.25 per unit, respectively. Under the Fourth Amended and Restated Operating Agreement of Kosmos Energy Holdings, as amended, (the Agreement) governing Kosmos Energy Holdings, the Convertible Preferred Units received distributions, if any, equal to the Accreted Value of the units, prior to any distributions to the common unit holders. The Accreted Value was defined in the Agreement as the unit purchase price plus the preferred return amount per unit equal to 7% of the Accreted Value per annum (compounded quarterly) for the first nine years after the year of Kosmos Energy Holdings initial operating agreement and 14% of the Accreted Value per annum (compounded quarterly) thereafter, unless a monetization event (as defined in the Agreement) occurred at which time the preferred return would revert to 7%. The holders of the Convertible Preferred Units received the accumulated preferred return upon the consummation of our IPO, as defined in the Agreement. The accumulated preferred return on the Convertible Preferred Units was recorded through the date of the offering. The amount was applied to additional paid-in capital first, with the remaining amount applied to the accumulated deficit. The Convertible Preferred Units were classified as mezzanine equity at December 31, 2010, as Kosmos Energy Holdings could not solely control the type of consideration issuable on the exchange and the Convertible Preferred Unit holders controlled Kosmos Energy Holdings Board of Directors.

We recorded accretion on the Convertible Preferred Units of $7.6 million and $24.4 million for the three and six months ended June 30, 2011, respectively.

14. Equity-based Compensation

Profit Units

Prior to our corporate reorganization, Kosmos Energy Holdings issued common units designated as profit units with a threshold value of $0.85 to $90 to employees, management and directors. Profit units, the defined term in the related agreements, are equity awards that are measured on the grant date and expensed over a vesting period of four years. Founding management and directors vested 20% as of the date of issuance and an additional 20% on the anniversary date for each of the next four years. Profit units issued to employees vested 50% on the second and fourth anniversary of the issuance date. Of the 100 million authorized common units, 15.7 million were designated as profit units.

The following is a summary of the Kosmos Energy Holdings profit unit activity immediately prior to the corporate reorganization:

	Profit Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2010	13,910	$ 1.76
Granted	1,783	15.71
Relinquished	(2,503)	0.12

Outstanding at May 16, 2011	13,190	3.96

A summary of the status of the Kosmos Energy Holdings unvested profit units immediately prior to the corporate reorganization were as follows:

	Unvested Profit Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2010	3,464	$ 1.60
Granted	1,783	15.71
Vested	(1,066)	1.09
Relinquished	(1,253)	0.10
Outstanding at May 16, 2011	2,928	11.02

Total compensation expense recognized in income was $0.8 million and $1.2 million for the three and six months ended June 30, 2011, respectively.

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The significant assumptions used to calculate the fair values of the profit units during 2011, as calculated using a binomial tree, were as follows: no dividend yield, expected volatility ranging from approximately 25% to 66%; risk-free interest rate ranging from 1.3% to 5.1%; expected life ranging from 1.2 to 8.1 years; and projected turnover rate of 7.0% for employees and none for management.

Restricted Stock Awards and Restricted Stock Units

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

In April 2011, the Board of Directors approved a Long-Term Incentive Plan (the LTIP), which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, restricted stock awards, restricted stock units, among other award types. The LTIP provides for the issuance of 24.5 million shares pursuant to awards under the plan, in addition to the 10.0 million restricted stock awards exchanged for unvested profit units.

The following table shows the number of shares available for issuance pursuant to awards under the Company s LTIP at June 30, 2012:

	Shares (In thousands)
Approved and authorized awards(1)	24,503
Awards issued after May 16, 2011(1)	(16,799)
Awards forfeited(1)	1
Awards available for future grant	7,705

(1) Excludes 10.0 million restricted stock awards that were exchanged for unvested profit units and any related forfeitures of such awards. Also, excludes forfeited restricted stock awards issued in connection with our initial public offering, which include the May 18, 2011 and June 15, 2011 award tranches, as these awards are not available for future grant.

The Company records compensation expense equal to the fair value of share-based payments over the vesting periods of the LTIP awards. The Company recorded compensation expense from awards granted under our LTIP of $17.6 million and $7.9 million during the three months ended June 30, 2012 and 2011, respectively, and $38.9 and $7.9 million during the six months ended June 30, 2012 and 2011, respectively. Subsequent to May 16, 2011, 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.

The following table reflects the outstanding restricted stock awards as of June 30, 2012:

	Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2011	17,195	$ 13.36	3,522	$ 13.21
Granted	578	12.06	303	9.45
Forfeited	(624)	13.37	(101)	13.57
Vested	(5,022)	10.23		
Outstanding at June 30, 2012	12,127	14.59	3,724	12.89

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The following table reflects the outstanding restricted stock units as of June 30, 2012:

	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, 2011		$		$
Granted	593	10.98	489	15.81
Forfeited				
Vested				
Outstanding at June 30, 2012	593	10.98	489	15.81

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

For restricted stock awards 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 100% of the awards granted. The grant date fair value of these awards ranged from $6.70 to $13.57 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 41.3% to 56.7%. 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 0.5% to 1.1%.

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 of these awards was $15.81 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 was 54.0%. 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 was 0.5%.

15. Income Taxes

The income tax expense (benefit) was $22.5 million and $11.5 million for the three months ended June 30, 2012 and 2011, respectively, and was $38.8 million and $(2.0) million for the six months ended June 30, 2012 and 2011, respectively. The income tax provision consists of U.S. and Ghanaian income and Texas margin taxes.

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(In thousands)			
Bermuda	$ (3,251)	$ (8,846)	$ (6,419)	$ (8,846)
United States	3,035	411	6,347	809
Foreign other	(2,106)	10,879	(23,505)	(57,681)
Income (loss) before income taxes	$ (2,322)	$ 2,444	$ (23,577)	$ (65,718)

Our effective tax rate for the three months ended June 30, 2012 and 2011 was (970)% and 472%, respectively. For the six months ended June 30, 2012 and 2011 our effective tax rate was (165)% and 3%. The effective tax rate for the United States is approximately 277% and 41% for the three months ended June 30, 2012 and 2011, respectively, and 152% and 39% for the six months ended June 30, 2012 and 2011, respectively. The increase in the effective tax rate in the United States resulted from the difference between the amount deductible on our tax return for vested stock awards and the amount of cumulative compensation cost recognized for financial reporting purposes. The effective tax rate for Ghana is approximately 35% for all periods presented. The effective tax rate for our other foreign jurisdictions is 0%. Our other foreign jurisdictions have a 0% effective tax rate because they reside in countries with a 0% statutory rate, or we have experienced losses in those countries and have a full valuation allowance reserved against their ending net deferred tax assets.

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The Company has no material unrecognized income tax benefits.

A subsidiary of the Company files a U.S. federal income tax return and a Texas margin tax return. In addition to the United States, the Company files income tax returns in the countries in which we operate. The Company is open to U.S. federal income tax examinations for tax years 2009 through 2011 and to Texas margin tax examinations for the tax years 2007 through 2011. In addition, the Company is open to income tax examinations for tax years as early as 2004 in its significant foreign jurisdictions (Ghana, Cameroon and Morocco).

The Company s policy is to recognize interest and penalties related to income tax matters in income tax expense if they are considered probable, but has had no need to accrue any to date.

16. Net Income (Loss) Per Share

In the calculation of basic net income (loss) per common share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company s participating securities do not participate in undistributed net losses because they are not contractually obligated to do so. The computation of diluted net income (loss) per share attributable to common shareholders reflects the potential dilution that could occur if securities or other contracts to issue common shares that are dilutive were exercised or converted into common shares or resulted in the issuance of common shares that would then share in the earnings of the Company. During periods in which the Company realizes a loss from continuing operations attributable to common shareholders, securities would not be dilutive to net loss per share and conversion into common shares is assumed not to occur. Diluted net income (loss) per share attributable to common shareholders is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented.

Basic net income (loss) per share attributable to common shareholders is computed as (i) net income (loss) attributable to common shareholders, (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. The Company s diluted net income (loss) per share attributable to common shareholders is computed as (i) basic net income (loss) attributable to common shareholders, (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding.

Pro forma net income (loss) attributable to common shares reflects net income (loss) as reported and gives effect to an adjustment to remove accretion on the Convertible Preferred Units. In our pro forma basic and diluted income (loss) per share attributable to common shareholders calculation, we assumed the conversion of the Convertible Preferred Units occurred on January 1, 2011 and, therefore, we have removed the related accretion to determine pro forma net income (loss).

Pro forma weighted average common shares outstanding used in the computation of pro forma basic and diluted income (loss) per share attributable to common shareholders has been computed taking into account (1) the conversion ratio at the time of the IPO of all common units and Convertible Preferred Units into common shares as if the conversion occurred as of the beginning of the year and (2) the 34.5 million common shares issued by the Company in the IPO, which included 1.5 million common shares issued pursuant to the over-allotment option exercised by the underwriters of the IPO.

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The following table is a reconciliation of the Company s net income (loss) attributable to common shareholders to basic and pro forma basic net income (loss) attributable to common shareholders and to diluted and pro forma diluted net income (loss) attributable to common shareholders and a reconciliation of basic and pro forma basic weighted average common shares outstanding to diluted and pro forma diluted weighted average common shares outstanding for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Month Ended June 30, 2012	Six Month Ended June 30, 2011
	(In thousands, except per share data)			
Numerator:				
Net loss attributable to common shareholders	$ (24,843)	$ (16,686)	$ (62,384)	$ (88,184)
Less: Basic income allocable to participating securities(1)				
Basic net loss attributable to common shareholders	(24,843)		(62,384)	
Plus: Accretion to redemption value of convertible preferred units		7,595		24,442
Pro forma basic net loss attributable to common shareholders		(9,091)		(63,742)
Diluted adjustments to income allocable to participating securities(1)				
Diluted net loss attributable to common shareholders	$ (24,843)		$ (62,384)	
Pro forma diluted net loss attributable to common shareholders		$ (9,091)		$ (63,742)
Denominator:				
Weighted average number of shares used to compute net loss per share:				
Basic	370,720		369,973	
Restricted stock awards(1)(2)				
Diluted	370,720		369,973	
Pro forma basic		348,820		340,030
Pro forma restricted stock awards(1)(2)				
Pro forma diluted		348,820		340,030
Net loss per share attributable to common shareholders:				
Basic	$ (0.07)		$ (0.17)	
Diluted	$ (0.07)		$ (0.17)	
Pro forma basic		$ (0.03)		$ (0.19)
Pro forma diluted		$ (0.03)		$ (0.19)

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

(2) Due to our basic net loss attributable to common shareholders for the three and six months ended June 30, 2012, we excluded 16.9 million outstanding restricted stock awards and restricted stock units from the computations of diluted net loss per share because the effect would have been anti-dilutive. For the three and six months ended June 30, 2011, we excluded 20.6 million outstanding restricted stock awards from the computations of pro forma diluted net loss per share because the effect would have been anti-dilutive.

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17. Contingencies

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 statements.

18. Subsequent Events

Derivatives

In July 2012, we entered into three-way collar contracts for 1.5 million Bbls from January 2013 through December 2013 with a floor price of $95.00 per Bbl, a ceiling price of $105.00 per Bbl and a call price of $125.00 per Bbl. The three-way collar contracts are indexed to Dated Brent prices and have a weighted average deferred premium of $4.82 per Bbl.

Restricted Cash

Effective July 2012, we designated an additional $27.0 million as long-term restricted cash used to cash collateralize performance guarantees related to our recently acquired petroleum agreements.

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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, 2011, 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 information that involves 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 an independent oil and gas exploration and production company currently focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production, major discoveries and exploration prospects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Mauritania, Morocco and Suriname and onshore Cameroon.

We were incorporated pursuant to the laws of Bermuda as Kosmos Energy Ltd. in January 2011 to become a holding company for Kosmos Energy Holdings. Pursuant to the terms of a corporate reorganization that was completed immediately prior to the closing of Kosmos Energy Ltd. s IPO on May 16, 2011, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. As a result, Kosmos Energy Holdings became wholly owned by Kosmos Energy Ltd.

Recent Highlights

During the second quarter of 2012, we had one lifting of oil totaling 997 MBbl from our Jubilee Field production resulting in revenues of $112.2 million. Our average realized price per barrel was $112.60.

A total of 17 development wells have been drilled during the Jubilee Field Phase 1 development. The Jubilee Field Phase 1A PoD was approved by the Ministry of Energy and GNPC in January 2012. The Phase 1A PoD includes eight additional wells to be drilled beginning in 2012, including five production wells and three water injection wells.

Ghana exploration and appraisal activity

In January 2012, the Ntomme-2A appraisal well confirmed a downdip extension of the Ntomme Field on the DT Block. The well encountered high-quality stacked reservoir sandstones. A drill stem test was performed on the well in May 2012, which successfully flowed oil from multiple zones in the reservoir and confirmed continuity with the Ntomme discovery well. Fluid samples recovered from the well indicate an oil gravity of approximately 35 degrees API.

In July 2012, the Wawa-1 exploration well made a hydrocarbon discovery on the DT Block. Analysis of well results, including wireline logs, reservoir pressures and fluid samples, indicated the well encountered gas-condensate and oil-bearing pay. Fluid samples recovered from the well indicate an oil gravity of between 38 and 44 degrees API.

The WCTP PA, which governs our activities related to the WCTP Block, has a duration of 30 years from its effective date (July 2004); however, in July 2011, at the end of the seven-year exploration phase, parts of the WCTP Block on which we had not declared a discovery area, were not in a development and production area or were not in the Jubilee Unit were subject to relinquishment (WCTP Relinquishment Area). Our existing discoveries within the WCTP Block have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase and these are Akasa, Banda, Mahogany and Teak. In addition, we have disputed the relinquishment of the area around the Cedrela prospect. In July 2011, immediately prior to Kosmos receiving the drilling rig from another operator, damage to the rig incurred during preparations to move the rig to the WCTP Block rendered the rig incapable of drilling the Cedrela-1 exploration well prior to the end of the WCTP exploration period on July 21, 2011. As a result of this unforeseen delay in the drilling of the Cedrela-1 exploration well, the Company, as Operator for the WCTP PA Block partners, delivered a Notice of Force Majeure. The Ministry of Energy and GNPC did not agree this event was Force Majeure. On August 24, 2011, we as Operator of the WCTP Block and on behalf of the WCTP PA Block partners, delivered a Notice of Dispute to the Ministry of Energy and GNPC as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government of Ghana regarding our rights to drill the Cedrela-1 exploration well. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter. The issue continues to be discussed in an effort to reach a mutually agreed upon resolution among the parties.

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We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. We and our WCTP Block partners exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. We and our WCTP Block partners, the Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third party offer GNPC may receive for the WCTP Relinquishment Area.

In February 2012, we exercised a right under the existing joint operating agreement to acquire the 4.05% participating interest of Sabre in the DT Block. In May 2012, Kosmos and Sabre reached a mutual agreement to terminate this acquisition.

Drilling of the Teak-4A appraisal well was completed in May 2012. The well encountered non-commercial reservoirs and accordingly was plugged and abandoned. Total well related costs incurred from inception through June 30, 2012 of $15.8 million are included in exploration expenses in the accompanying consolidated statement of operations.

Mauritania

In April 2012, we completed negotiations with Mauritania s Ministry of Petroleum, Energy and Mines and executed separate petroleum contracts covering Blocks C8, C12 and C13 offshore Mauritania. Kosmos is the operator and has a 90% participating interest in each of these blocks. The Government of Mauritania has a 10% carried interest during the exploration period and the option to participate in any discovery on these blocks, and if it elects to exercise such option its participation interest would be between 10% and 14%. The first phase of the exploration period of the petroleum contract covering each of Blocks C8, C12 and C13 is four years in duration. These contracts were officially gazetted by the Government of Mauritania on June 15, 2012, thereby establishing the effective date for the petroleum contracts.

Our blocks in Mauritania cover 6.7 million acres (27,200 square kilometers) and are located within the western margin of the proven Mauritanian salt basin, on the Atlantic passive margin. The source rock in the basin is the same age and type as the source rock generated by the petroleum system in the Jubilee Field. Additionally, we believe the play model in the basin is similar to the play model found in the Jubilee Field. A petroleum system in Mauritania has been proven by the presence of offshore producing fields in adjacent blocks to those we hold.

We have an estimated $12.6 million in work commitments to perform exploration activities on our petroleum contracts in Mauritania. We plan to acquire seismic data in our blocks offshore Mauritania in 2013 to further define prospectivity on the blocks.

Morocco

In May 2012, we received joint ministerial approval from the Moroccan government to acquire an additional 18.75% participating interest in the Foum Assaka Offshore Block from Pathfinder Hydrocarbon Ventures Ltd., one of our block partners. Certain governmental approvals and processes are still required to be completed before this acquisition can be closed. After completing the acquisition, our participating interest in the Foum Assaka Offshore Block will be 56.25%.

Suriname

In May 2012, Kosmos entered into an agreement with Chevron Global Energy Inc. (Chevron) under which Kosmos will assign half of its interest in Block 42 and Block 45, offshore Suriname, to Chevron. Upon receipt of approval from the Suriname government and the closing of the agreement, each party will have a 50% working interest in Block 42 and Block 45.

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Results of Operations

Certain operating results and statistics for the comparative second quarters of 2012 and 2011 are included in the following table:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(In thousands, except per barrel data)			
Sales volumes:				
MBbl	997	996	1,928	1,985
Revenues:				
Oil sales	$ 112,214	$ 124,083	$ 227,985	$ 216,652
Average sales price per Bbl	112.60	124.62	118.25	109.14
Costs:				
Oil production, excluding workovers	$ 9,333	$ 14,301	$ 16,659	$ 34,296
Oil production, workovers	10,259		10,259	
Total oil production costs	19,592	14,301	26,918	34,296
Depletion	31,288	21,711	61,343	44,096
Average cost per Bbl:				
Oil production, excluding workovers	9.37	14.36	8.64	17.28
Oil production, workovers	10.29		5.32	
Total oil production costs	19.66	14.36	13.96	17.28
Depletion	31.39	21.80	31.82	22.21
Oil production cost and depletion costs	$ 51.05	$ 36.16	$ 45.78	$ 39.49

The following table shows the number of wells in the process of drilling or in active completion stages, and the number of wells suspended or awaiting completion as of June 30, 2012:

	Wells in the Process of Drilling or in Active Completion				Wells Suspended or Awaiting Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
West Cape Three Points					8	2.47		
Deepwater Tano	1	0.18			10	1.80		
Jubilee Unit			1	0.24			3	0.72

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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 June 30, 2012 compared to three months ended June 30, 2011

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 112,214	$ 124,083	$ (11,869)
Interest income	282	2,613	(2,331)
Other income	175	157	18
Total revenues and other income	112,671	126,853	(14,182)
Costs and expenses:			
Oil and gas production	19,592	14,301	5,291
Exploration expenses	16,901	85,220	(68,319)
General and administrative	34,799	19,760	15,039
Depletion and depreciation	32,999	22,869	10,130
Amortization deferred financing costs	2,194	2,194	
Interest expense	10,446	18,400	(7,954)
Derivatives, net	(1,982)	1,363	(3,345)
Doubtful accounts expense		(39,782)	39,782
Other expenses, net	44	84	(40)
Total costs and expenses	114,993	124,409	(9,416)
Income (loss) before income taxes	(2,322)	2,444	(4,766)
Income tax expense	22,521	11,535	10,986
Net loss	$ (24,843)	$ (9,091)	$ (15,752)

Oil and gas revenue. Oil and gas revenue decreased $11.9 million during the three months ended June 30, 2012, as compared with the three months ended June 30, 2011 due to a lower average realized price per barrel.

Oil and gas production. Oil and gas production costs increased $5.3 million during the three months ended June 30, 2012, as compared with the three months ended June 30, 2011 primarily due to workover costs for acid stimulations on three Jubilee Field wells, offset by a decrease due to the purchase of the FPSO in December 2011. During the three months ended June 30, 2012, the FPSO costs are being capitalized and expensed as depletion. Prior to the acquisition of the FPSO, we leased the FPSO from a third party and the lease costs were included in oil and gas production costs.

Exploration expenses. Exploration expenses decreased $68.3 million during the three months ended June 30, 2012, as compared with the three months ended June 30, 2011. During the three months ended June 30, 2012, we incurred $10.1 million of unsuccessful well costs related to the Ghana Teak-4A appraisal well. During the three months ended June 30, 2011, we incurred $79.9 million of unsuccessful well costs, primarily related to the Cameroon N gata-1, Cameroon Mombe-1, Ghana Banda-1 and Ghana Odum exploration wells.

General and administrative. General and administrative costs increased $15.0 million during the three months ended June 30, 2012, as compared with the three months ended June 30, 2011, primarily due to increases in non-cash expenses for equity-based compensation and an increase in staffing. Total non-cash general and administrative costs were $17.6 million and $8.7 million for the three months ended June 30, 2012 and 2011, respectively.

Depletion and depreciation. Depletion and depreciation increased $10.1 million during the three months ended June 30, 2012, as compared with the three months ended June 30, 2011, primarily due to an increase in the cost basis of our oil and gas properties related to the purchase of the FPSO and an increase in the number of completed wells.

Interest expense. Interest expense decreased $8.0 million during the three months ended June 30, 2012, as compared with the three months ended June 30, 2011, primarily due to a decrease in the unrealized loss on the interest rate derivative instruments related to changes in fair value and a lower weighted average interest rate on our commercial debt facility (the Facility) for the three months ended June 30, 2012.

Doubtful accounts expense. During the second quarter of 2011, we released a $39.8 million allowance for doubtful accounts, related to a receivable in default. We received the full amount of the receivable during the third quarter of 2011.

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Income tax expense. Income tax expense increased $11.0 million during the three months ended June 30, 2012, as compared to the three months ended June 30, 2011 due to an increase in net income from our Ghanaian and U.S. subsidiaries .

Six months ended June 30, 2012 compared to six months ended June 30, 2011

	Six months Ended June 30, 2012	Six months Ended June 30, 2011	Increase (Decrease)
		(In thousands)	
Revenues and other income:			
Oil and gas revenue	$ 227,985	$ 216,652	$ 11,333
Interest income	1,028	4,967	(3,939)
Other income	205	644	(439)
Total revenues and other income	229,218	222,263	6,955
Costs and expenses:			
Oil and gas production	26,918	34,296	(7,378)
Exploration expenses	56,545	93,652	(37,107)
General and administrative	74,122	33,047	41,075
Depletion and depreciation	64,648	46,367	18,281
Amortization deferred financing costs	4,388	11,805	(7,417)
Interest expense	23,504	38,658	(15,154)
Derivatives, net	1,878	10,234	(8,356)
Loss on extinguishment of debt		59,643	(59,643)
Doubtful accounts expense		(39,782)	39,782
Other expenses, net	792	61	731
Total costs and expenses	252,795	287,981	(35,186)
Income (loss) before income taxes	(23,577)	(65,718)	42,141
Income tax expense (benefit)	38,807	(1,976)	40,783
Net loss	$ (62,384)	$ (63,742)	$ 1,358

Oil and gas revenue. Oil and gas revenue increased $11.3 million during the six months ended June 30, 2012, as compared with the six months ended June 30, 2011 primarily due to a higher average realized price per barrel during the six months ended June 30, 2012.

Oil and gas production. Oil and gas production costs decreased $7.4 million during the six months ended June 30, 2012, as compared with the six months ended June 30, 2011 primarily due to a decrease related to the purchase of the FPSO in December 2011 partially offset by workover costs for acid stimulations on three Jubilee Field wells, During the six months ended June 30, 2012, the FPSO costs are being capitalized and expensed as depletion. Prior to the acquisition of the FPSO, we leased the FPSO from a third party and the lease costs were included in oil and gas production costs.

Exploration expenses. Exploration expenses decreased $37.1 million during the six months ended June 30, 2012, as compared with the six months ended June 30, 2011. During the six months ended June 30, 2012, we incurred $33.4 million for seismic costs for Morocco, Ghana and Cameroon and $19.2 million of unsuccessful well costs, primarily related to the Ghana Teak-4A appraisal well. During the six months ended June 30, 2011, the Company incurred $83.3 million of unsuccessful well costs primarily related to the Cameroon N gata-1, Cameroon Mombe-1, Ghana Makore-1, Ghana Banda-1 and Ghana Odum exploration wells and $10.2 million for seismic costs primarily for Ghana, Cameroon and new ventures.

General and administrative. General and administrative costs increased $41.1 million during the six months ended June 30, 2012, as compared with the six months ended June 30, 2011, due to increases in non-cash expenses of $29.7 million for equity-based compensation and an increase in staffing. Total non-cash general and administrative costs were $38.9 million and $9.1 million for the six months ended June 30, 2012 and 2011, respectively.

Depletion and depreciation. Depletion and depreciation increased $18.3 million during the six months ended June 30, 2012, as compared with the six months ended June 30, 2011, primarily due to an increase in the cost basis of our oil and gas properties related to the purchase of the FPSO and an increase in the number of completed wells.

Amortization deferred financing costs and *Loss on extinguishment of debt.* In March 2011, we refinanced our existing commercial debt facilities. As part of the transaction, we incurred approximately $52.3 million of deferred financing costs, in addition to our existing unamortized deferred financing costs of $68.6 million. As a result of the transaction, we recorded a $59.6 million loss on the extinguishment of debt. The remaining costs were capitalized and are being amortized over the term of the Facility entered into

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in March 2011. The related amortization of deferred financing costs decreased by $7.4 million during the six months ended June 30, 2012, as compared to the six months ended June 30, 2011, due to the decrease in capitalized deferred financing costs and the longer term associated with the new Facility.

Interest expense. Interest expense decreased $15.2 million during the six months ended June 30, 2012, as compared with the six months ended June 30, 2011, primarily due to a decrease in the unrealized loss on the interest rate derivative instruments related to changes in fair value and a lower weighted average interest rate on the Facility during the six months ended June 30, 2012.

Income tax expense (benefit). Income tax expense increased $40.8 million during the six months ended June 30, 2012, as compared to the six months ended June 30, 2011 due to an increase in net income from our Ghanaian and U.S. subsidiaries.

Liquidity and Capital Resources

We are actively engaged in an ongoing process to anticipate and meet our funding requirements related to exploring for and developing oil and natural gas resources in Africa and South America. We have historically secured funding from equity commitments and commercial debt facilities to meet our ongoing liquidity requirements. In addition, we received our first oil revenues in January 2011 from Jubilee Field production and the cash flows generated from our operating activities may provide an additional source of future funding. Additionally, existing cash on hand will be utilized as a source to fund our operating and investing activities.

Significant Sources of Capital

In March 2011, the Company secured a $2.0 billion Facility from a number of financial institutions and extinguished the then existing commercial debt facilities. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. The total loan commitments of the Facility may be increased up to a maximum of $3.0 billion if the lenders increase their commitments or if loan commitments from new financial institutions are added. In all cases, however, the availability under the Facility is limited by borrowing base capacity, which is redetermined semi-annually. The International Finance Corporation entered the Facility in February 2012. The terms and conditions of the Facility remained consistent with the original terms and conditions, and the total commitment under the Facility remained unchanged.

As of June 30, 2012, borrowings under the Facility totaled $1.1 billion. As of June 30, 2012, the undrawn availability under the Facility was an additional $50.0 million.

The interest is the aggregate of the applicable margin (3.25% to 4.75%, depending on the amount of the Facility that is being utilized and the length of time that has passed from the date the Facility was entered into); LIBOR; and mandatory cost (if any, as defined in the Facility). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). Kosmos pays commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees for the lenders are equal to 40% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. The Company recognizes interest expense in accordance with ASC 835 Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of borrowings under the Facility. Accordingly, we recognized interest expense in excess of interest currently payable of $1.3 million and $1.2 million during the three months ended June 30, 2012 and 2011, respectively, and $3.1 million and $1.2 million during the six months ended June 30, 2012 and 2011, respectively.

The Facility provides a revolving-credit and letter of credit facility for an availability period that expires on May 15, 2014 (in the case of the revolving-credit facility) and on the final maturity date (in the case of the letter of credit facility). The available facility amount is subject to borrowing base constraints and also is constrained by the amortization schedule (once repayments under the Facility begin). As of May 15, 2014, outstanding borrowings will be subject to an amortization schedule. The first required payment could be as early as June 15, 2014, subject to the level of outstanding borrowings. The Facility has a final maturity date of March 29, 2018.

Kosmos has the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, was previously determined each year on June 15 and December 15 as part of a forecast that is prepared by and agreed to by Kosmos and the Technical and Modeling Banks. In April 2012, the lenders agreed to change the borrowing base determination dates to April 15 and October 15. The formula to calculate the borrowing base amount is based, in part, on the sum of the net present values of net cash flows and relevant capital expenditures, reduced by certain ratios.

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If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by us.

We were in compliance with the financial covenants contained in the Facility as of April 19, 2012, our most recent forecast date, which requires the maintenance of:

- the field life cover ratio, not less than 1.30x; and
- the loan life cover ratio, not less than 1.10x.

The field life cover ratio is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the depletion of the Jubilee Field plus the net present value of capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility. The loan life cover ratio is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the final maturity date of the Facility plus the net present value of capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility.

Capital Expenditures and Investments

We expect to incur substantial costs as we continue to develop our oil and natural gas prospects and as we:

- complete our 2012 exploration and appraisal drilling program in our license areas;
- develop our discoveries that we determine to be commercially viable;
- purchase and analyze seismic and other geological and geophysical data to identify future prospects; and
- invest in additional oil and natural gas leases and licenses and potentially make additional acquisitions.

We have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our working interests in our prospects, the costs involved in developing or participating in the development of a prospect, the timing of third-party projects, and the availability of suitable equipment and qualified personnel. These assumptions are inherently subject to significant business, political, economic, regulatory, environmental and competitive uncertainties, contingencies and risks, all of which are difficult to predict and many of which are beyond our control. We may need to raise additional funds more quickly if one or more of our assumptions proves to be incorrect or if we choose to expand our hydrocarbon asset acquisition, exploration, appraisal or development efforts more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

2012 Capital Program

We reduced our estimate for the 2012 capital program to approximately $500 million for the year ending December 31, 2012. With the success of the Company s acid treatment program at Jubilee, we do not anticipate performing any further sidetrack operations in the current year. The removal of these sidetracks, along with updated appraisal plans on the Company s WCTP Block, accounts for the reduction in estimated capital expenditures. The 2012 capital expenditure budget consists of:

- approximately 45% for developmental related expenditures; and

- approximately 55% for exploration and appraisal related expenditures, including new ventures exploration and expanding our license portfolio (including geological and geophysical expenses).

The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success of our drilling results. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and natural gas and the prices we receive from the sale of these commodities, the success of our exploration and appraisal drilling program, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, and the actual cost of exploration, appraisal and development of our oil and natural gas assets.

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The following table presents our liquidity and financial position as of June 30, 2012:

	June 30, 2012 (In thousands)
Cash	$ 629,951
Drawings under the commercial debt facility	1,110,000
Net debt	480,049
Total of unused borrowing base	50,000
Unused borrowing base plus cash	679,951

Cash Flows

	Six months Ended June 30, 2012	Six months Ended June 30, 2011
	(In thousands)	
Net cash provided by (used in):		
Operating activities	$ 160,685	$ 54,499
Investing activities	(194,194)	(119,543)
Financing activities	(9,632)	782,908

Operating activities. Net cash provided by operating activities for the six months ended June 30, 2012 was $160.7 million, compared with net cash provided in operating activities for the six months ended June 30, 2011 of $54.5 million. The increase in cash provided by operating activities in the six months ended June 30, 2012 compared with the same period in 2011 was primarily due to timing of cash receipts for oil sales and other working capital changes.

Investing activities. Net cash used in investing activities for the six months ended June 30, 2012 was $194.2 million, compared with net cash used in investing activities for the six months ended June 30, 2011 of $119.5 million. The increase in cash used in investing activities in the six months ended June 30, 2012 compared with the same period in 2011 was primarily attributable to changes in restricted cash, notes receivable and expenditures for oil and gas assets primarily in Ghana for development activities. During the six months ended June 30, 2011, we released $112.0 million of associated restricted cash and set aside $27.7 million primarily related to requirements under the Facility.

Financing activities. Net cash used by financing activities for the six months ended June 30, 2012 was $9.6 million, compared with net cash provided by financing activities for the six months ended June 30, 2011 of $782.9 million. The decrease in cash provided by financing activities in the six months ended June 30, 2012 compared with the same period in 2011 was primarily due to lower net borrowings on the Facility of $255.0 million offset by a decrease of $51.2 million in cash used for deferred financing costs. Additionally for the six months ended June 30, 2011, we received net proceeds from the IPO of $580.4 million

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Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of June 30, 2012:

	Payments Due By Year(3)						
	Total	2012(4)	2013	2014 (In thousands)	2015	2016	Thereafter
Commercial debt facility(1)	$ 1,110,000	$	$	$	$ 110,000	$ 444,444	$ 555,556
Interest payments on commercial debt facility(2)	263,962	23,005	47,039	50,925	54,888	55,336	32,769
Operating leases	21,797	234	2,821	2,921	3,022	3,122	9,677

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of June 30, 2012. Any increases or decreases in the level of borrowings 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 curve at the reporting date.

(3) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes $16.7 million of commitments for exploration activities in our petroleum contracts. Does not include any well commitments we may have under our petroleum contracts.

(4) Represents payments for the period July 1, 2012 through December 31, 2012.

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

[redacted]

Variable rate debt:							
Commercial debt facility maturities	$	$	$	$ 110,000	$ 444,444	$ 555,556	$ (1,110,000)
Weighted average interest rate	4.11%	4.24%	4.59%	4.94%	6.23%	7.00%	
Interest rate swaps:							
Notional debt amount(1)	$ 114,896	$ 91,683	$ 47,033	$ 16,875	$ 6,250	$	$ (3,037)
Fixed rate payable	2.22%	2.22%	2.22%	2.22%	2.22%		

Variable rate receivable(2)	0.73%	0.74%	0.80%	1.11%	1.48%		
Notional debt amount(1)	$ 114,896	$ 91,683	$ 47,033	$ 16,875	$ 6,250	$	$ (3,240)
Fixed rate payable	2.31%	2.31%	2.31%	2.31%	2.31%		
Variable rate receivable(2)	0.73%	0.74%	0.80%	1.11%	1.48%		
Notional debt amount(1)(3)	$ 49,751	$ 19,057	$ 1,868	$	$	$	$ (108)
Fixed rate payable	0.98%	0.98%	0.98%				
Variable rate receivable(2)	0.73%	0.74%	0.76%				
Notional debt amount(1)(4)	$ 26,877	$ 24,680	$ 38,434	$ 23,137	$	$	$ (479)
Fixed rate payable	1.34%	1.34%	1.34%	1.34%			
Variable rate receivable(2)	0.73%	0.74%	0.80%	1.24%			

(1) Represents weighted average notional contract amounts of interest rate derivatives.

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

(3) For 2014, represents notional amount from January June 2014.

(4) For 2015, represents notional amount from January June 2015.

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Off-Balance Sheet Arrangements

As of June 30, 2012, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies

We consider accounting policies related to our revenue recognition, exploration and development costs, receivables, income taxes, derivatives 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. These policies 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, 2011.

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 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 Ghana, Cameroon, Mauritania, Morocco or Suriname (or their respective national oil companies) or any other federal, state or local governments, 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 risks and other operational and environmental hazards;
- current and future government regulation of the oil and gas industry;
- cost of compliance, and our and our partners ability to comply, with laws and regulations;

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- changes in environmental, health and safety or climate change laws, greenhouse gas regulation or the implementation, or interpretation, of those laws and regulations;
- environmental liabilities;
- geological, reservoir, technical, drilling, production and processing problems;
- military operations, civil unrest, terrorist acts, wars or embargoes;
- the cost and availability of adequate insurance coverage;
- our vulnerability to severe weather events; and
- other risk factors discussed in the Item 1A. Risk Factors section of this quarterly report on Form 10-Q and our annual report on Form 10-K.

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

Item 3. Quantitative and Qualitative 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 they are 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 speculation.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the six months ending June 30, 2012:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates (In thousands)	Total
Fair value of contracts outstanding as of December 31, 2011	$ (24,760)	$ (8,074)	$ (32,834)
Changes in contract fair value	(1,878)	(1,435)	(3,313)
Contract maturities (settlements)	8,163	2,645	10,808
Fair value of contracts outstanding as of June 30, 2012	$ (18,475)	$ (6,864)	$ (25,339)

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 purchased puts and swaps with calls.

We manage and control market and counterparty credit risk in accordance with policies and guidelines approved by the Kosmos Board of Directors. In accordance with these policies and guidelines, we determine the appropriate timing and extent of derivative transactions. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. See Note 10 Derivative Financial Instruments in our consolidated financial statements for a description of the accounting procedures we follow relative to our derivative financial instruments.

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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 June 30, 2012:

				Weighted Average Price per Bbl			Asset(Liability)
Term	**Type of Contract**	**Bbls per day**	**Deferred Premium**	**Puts**	**Swaps**	**Calls**	**Fair Value at June 30, 2012 (1)(2)**
2012:							
July - December	Purchased puts	4,739	$ 6.79	$ 61.56	$	$	$ (5,508)
August - December	Swaps with calls	6,536			97.21	110.00	1,512
2013(3):							
January - December	Purchased puts	2,515	$ 7.32	$ 61.73	$	$	$ (5,474)

(1) Fair values are based on the average forward Dated Brent oil prices on June 30, 2012 which by year are: 2012 - $97.64; and 2013 - $97.42. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on July 31, 2012 market quotes by year are: 2012 - $103.67 and 2013 - $101.04.

(2) Excludes $9.2 million of cash settlements made on our purchased puts and compound options which were settled in the month subsequent to period end.

(3) In July 2012, we entered into three-way collar contracts for 1.5 million barrels from January 2013 through December 2013 with a floor price of $95.00 per Bbl, a ceiling price of $105.00 per Bbl and a call price of $125.00 per Bbl. The three-way collar contracts are indexed to Dated Brent pricing and have a weighted average deferred premium of $4.82 per Bbl.

Interest Rate Sensitivity

At June 30, 2012, we had indebtedness outstanding under our Facility of $1.1 billion, of which $803.6 million bore interest at floating rates. The weighted average annual interest rate incurred on this indebtedness for the six months ended June 30, 2012, was approximately 4.1%. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $0.2 million in interest expense per year on our Facility.

As of June 30, 2012, the fair market value of our interest rate swaps was a net liability of approximately $6.9 million. If LIBOR increased 10%, we estimate the liability would decrease to approximately $6.4 million, and if LIBOR decreased 10%, we estimate the liability would increase to approximately $7.3 million.

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. Based on that evaluation, the Company s Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of June 30, 2012.

For the quarter ended December 31, 2011, management determined that a material weakness existed in our internal controls over financial reporting because the Company did not maintain effective controls over the determination and reporting of the provision for income taxes. Specifically, management did not perform a sufficiently precise review to ensure the completeness and accuracy of the Company s calculation of its income tax provision related to our treatment of unrealized derivative losses. Management has implemented remediation steps to address the material weakness and to improve our internal control over financial reporting. Based on the remediation steps taken, management believes that the material weakness identified above no longer exists.

Evaluation of Changes in Internal Control over Financial Reporting. Except as noted above, there were no changes in our internal controls over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We have begun the process of documenting, reviewing and, as appropriate, improving our internal controls and procedures in anticipation of becoming subject to the SEC rules concerning internal control over financial reporting, which take effect beginning with the filing of our second annual report on Form 10-K due in March 2013.

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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.

Item 1A. Risk Factors

The risk factor below supplements the risks discussed in the Item 1A. Risk Factors section of our annual report on Form 10-K.

We may be required to obtain third-party consents and/or complete certain governmental processes in order to complete the acquisition or disposal of blocks and licenses.

The acquisition of blocks and licenses by us or those we choose to sell such interests to may require third party consent, including from applicable national oil companies and government, regulatory or legislative authorities. In addition, certain governmental processes may be required to be completed in order for these acquisitions or dispositions to be finalized. We may not be able to commence exploration, development and production operations on any blocks or licenses (or similar interests) we have agreed to acquire, and may not be able to receive payment on any blocks or licenses (or similar interests) we have agreed to dispose of, until all such consents are received and governmental processes are completed. Furthermore, any delays in completing these requirements may affect our exploration timetable or financial condition. Upon entering into any agreement to complete a prospective acquisition or disposition transaction that is subject to third-party consent and/or the completion of governmental process, no assurance can be given that these consents will be obtained and/or these processes will be completed, and accordingly that such prospective transactions will close on a timely basis or otherwise.

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

There have been no material changes from the information concerning the use of proceeds from our IPO discussed in the Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities section of our annual report on Form 10-K.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information.

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

Item 6. Exhibits

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereto duly authorized.

		Kosmos Energy Ltd. (Registrant)
Date	August 6, 2012	/s/ W. GREG DUNLEVY W. Greg Dunlevy Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS

Exhibit Number	Description of Document
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Filed herewith.

** Furnished herewith.