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Item 8. Financial Statements and Supplementary Data

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

FORM 10-K/A
Amendment No. 1

(Mark One)

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

For the fiscal year ended December 31, 2011

☐ **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**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered:
Common Shares $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common shares held by non-affiliates, based on the per-share closing price of the registrant's common shares as of the last business day of the registrant's most recently completed second fiscal quarter was $1,351,055,403.

The number of the registrant's Common Shares outstanding as of February 17, 2012 was 390,098,205.

DOCUMENTS INCORPORATED BY REFERENCE

Part III, Items 10-14, is incorporated by reference from the Proxy Statement for the Annual Meeting of Shareholders to be held on May 11, 2012.

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

EXPLANATORY NOTE

We are filing this Amendment No. 1 on Form 10-K/A (the "Amended Filing") to our Annual Report on Form 10-K for the year ended December 31, 2011 originally filed with the Securities and Exchange Commission ("SEC") on March 1, 2012 (the "Original Filing") to present net income per share attributable to common shareholders for the period from the date of our Corporate Reorganization, May 16, 2011, to December 31, 2011, and to remove the previously presented pro forma net income per share attributable to common shareholders on the face of our consolidated statements of operations, to revise the weighted average number of shares used to compute net income per share attributable to common shareholders, and to update the related disclosures found in Part II—Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data.

In accordance with applicable SEC rules, this Amended Filing includes certifications from our Chief Executive Officer and Chief Financial Officer dated as of the date of this filing.

Except for the items noted above, no other information included in the Original Filing is being amended by this Amended Filing. The Amended Filing continues to speak as of the date of the Original Filing and we have not updated the Original Filing to reflect events occurring subsequent to the date of the Original Filing other than those associated with the presentation of net income per share attributable to common shareholders and the weighted average number of shares used to compute net income per share attributable to common shareholders on our consolidated statements of operations and in the related disclosure. Accordingly, this Amended Filing should be read in conjunction with our filings made with the SEC subsequent to the date of the Original Filing.

Background of the Restatement

We are filing this amendment to present net income per share attributable to common shareholders for the period subsequent to our Corporate Reorganization instead of the pro forma net income per share attributable to common shareholders previously presented. For the period from May 16, 2011 to December 31, 2011, the basic and diluted net income per share attributable to common shareholders of $0.09 on our consolidated statements of operations is greater than our original presentation of pro forma basic and diluted net income per share attributable to common shareholders of $0.06 even though our total earnings for the year ended December 31, 2011 have not changed. For the periods presented prior to our corporate reorganization, we do not calculate historical net income per share attributable to common shareholders because we did not have common stock outstanding, as defined in accounting literature, in those periods. For more information regarding the calculation of net income per share attributable to common shareholders, please refer to Note 16—Net Income Per Share (Restated).

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Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy Holdings and its subsidiaries prior to the completion of the corporate reorganization, which was completed in connection with our initial public offering ("IPO"), and Kosmos Energy Ltd. and its subsidiaries as of the completion of the corporate reorganization and thereafter. We have provided definitions for some of the industry terms used in this report in the "Glossary and Selected Abbreviations" beginning on page 2.

KOSMOS ENERGY LTD.
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.

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"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 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.
"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.

Cautionary Statement Regarding Forward-Looking Statements

This annual report on Form 10-K contains estimates and forward-looking statements, principally in "Item 1. Business," "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." Our estimates and forward-looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward-looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in our annual report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this annual report on Form 10-K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect. Our estimates and forward-looking statements may be influenced by the following factors, among others:

- our ability to find, acquire or gain access to other discoveries and prospects and to successfully develop 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, Morocco or Suriname (or their respective national oil companies) or any other federal, state or local governments or authorities, to us;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil and natural gas prices;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling risks and other operational and environmental hazards;
- current and future government regulation of the oil and gas industry;
- cost of compliance with laws and regulations;
- 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, 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 annual report on Form 10-K.

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

PART I

Item 1. Business

General

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 offshore Morocco and Suriname and onshore Cameroon. Kosmos is listed on the New York Stock Exchange ("NYSE") under the ticker symbol "KOS."

Following our formation in 2003, we acquired our initial portfolio of exploration licenses and established a new, major oil province in West Africa with the discovery of the Jubilee Field within the Tano Basin offshore Ghana in 2007. This was the first of our discoveries offshore Ghana; it was one of the largest oil discoveries worldwide in 2007 and is considered one of the largest finds offshore West Africa during the last decade. Oil production from the Jubilee Field commenced on November 28, 2010, and we generated revenues of $666.9 million during 2011 from oil sales from the Jubilee Field.

In the near-term, we are focused on maximizing production from the Jubilee Field development, and progressing the appraisal and development of our other discoveries in Ghana as well as the acquisition, exploration, appraisal and development of existing and new opportunities, including identifying, capturing and testing additional high-potential prospects to grow reserves and production.

Our Business Strategy

Grow proved reserves and production through exploration, appraisal and development

We plan to continue to produce and further develop the Jubilee Field, while completing appraisal of our existing discoveries (Tweneboa, Tweneboa Deep, Enyenra and Ntomme in the Deepwater Tano Block offshore Ghana ("DT Block") and Mahogany East, Teak, Akasa and Banda in the West Cape Three Points Block offshore Ghana ("WCTP Block")). In the event of a declaration of commerciality and approval of a plan of development, we intend to develop these discoveries to grow proved reserves and production. We also plan to drill exploration prospects in our asset portfolio, with the intent to further grow proved reserves and production should discoveries be made.

Apply our technically-driven culture, which fosters innovation and creativity, to continue our successful exploration and development program

We differentiate ourselves from other E&P companies through our approach to exploration and development. Our geoscientists, petroleum engineers and major projects personnel are pivotal to the success of our business strategy. We have created an environment that enables them to focus their knowledge, skills and experience on finding and developing oil fields. Culturally, we have an open, team-oriented work environment that fosters both creative and contrarian thinking. This approach allows us to fully consider and understand risk and reward and to deliberately and collectively pursue strategies that maximize value. We used this philosophy and approach to make discoveries in and produce from the Tano Basin offshore Ghana, a significant new petroleum system the industry previously did not consider either prospective or commercially viable.

Focus on rapidly developing our discoveries to initial production

We focus on maximizing returns through accelerating development to deliver early production. If a phased development strategy is deemed to be the optimal solution, we will seek to implement the approach early in the process. There are numerous benefits to pursuing a phased development to support our production growth plan. Importantly, a phased development strategy can provide for first oil production earlier than could otherwise be possible using traditional development techniques, which are disadvantaged by more time-consuming, costly and sequential appraisal and pre-development activities. In certain circumstances, we believe a phased approach can optimize full-field development through a better understanding of dynamic reservoir behavior and allows numerous activities to be performed in a parallel rather than a sequential manner. The initial phase of the Jubilee Field, for example, was brought on production at an earlier date by using a phased development approach, with further appraisal and pre-development activities performed in parallel and detailed engineering for the initial phase conducted simultaneously with the other project activities. In contrast, a traditional development approach consists of full appraisal, conceptual engineering, preliminary engineering, detail engineering, procurement and fabrication of facilities, development drilling and installation of facilities for the full-field development, all performed in sequence, before first production is achieved. This adds considerably more time to the development timeline. A phased approach provides dynamic reservoir performance information that allows the full-field development to be optimized. This approach also maximizes net asset value by refining appraisal and development plans based on experience gained in initial phases of production and by leveraging existing infrastructure as subsequent phases of development are implemented. Production and reservoir performance from the initial phase are monitored closely to determine the most efficient and effective techniques to maximize the recoverability of reserves in the most economic manner. Other benefits include minimizing upfront capital costs, reducing execution risks through smaller initial infrastructure requirements, and enabling cash flow from the initial phase of production to fund a portion of capital costs for subsequent phases.

First oil production from the Jubilee Field commenced on November 28, 2010, and we received our first oil revenues in early 2011. This development timeline from discovery to first oil was significantly less than the industry average of seven to ten years and set a record for a deepwater development at this water depth in West Africa. This condensed timeline reflects the lessons learned by members of our experienced management while leading other large scale deepwater developments, such as Ceiba offshore Equatorial Guinea and Neptune and Mensa in the U.S. Gulf of Mexico.

Identify, access and explore emerging regions and hydrocarbon plays

Our management and exploration team has demonstrated an ability to identify regions and hydrocarbon plays that yield multiple large commercial discoveries. We will continue to utilize our systematic and proven geologically focused approach to emerging petroleum systems where geological data suggests hydrocarbon accumulations are likely to exist, but where commercial discoveries have yet to be made. We believe this approach reduces the exploratory risk in poorly understood, under-explored or otherwise overlooked hydrocarbon basins that offer significant oil potential. This was the case with respect to the Late Cretaceous stratigraphy of West Africa, the niche in which we chose to build our exploration portfolio between 2004 and 2006. Many of our licenses share similar geologic characteristics focused on untested structural-stratigraphic traps. This exploration focus has proved successful, with the discovery of the Jubilee Field ushering in a new level of industry interest in Late Cretaceous petroleum systems across the Atlantic Margin, including play types that had previously been largely ignored.

This approach and focus, coupled with a first-mover advantage, provide a competitive advantage in identifying and accessing new strategic growth opportunities. We expect to continue to seek new opportunities where oil has not been discovered or produced in meaningful quantities by leveraging the skills of our experienced technical team. This includes our existing areas of interest as well as selectively expanding into other regions.

We may farm-in to new venture opportunities to undertake exploration in emerging basins, new plays and fairways to enhance and optimize our portfolio. Consistent with this strategy, we may also evaluate potential corporate and asset acquisition opportunities as a source of new ventures to replenish and expand our asset portfolio.

Kosmos Exploration Approach

Kosmos' exploration philosophy is deeply rooted in a fundamental, geologically based approach geared toward the identification of misunderstood, under-explored or overlooked petroleum systems. This process begins with detailed geologic studies that methodically assess a particular region's subsurface, with particular consideration to those attributes that lead to working petroleum systems. The process includes basin modeling to predict oil charge and fluid migration, as well as stratigraphic and structural analysis to identify reservoir/seal pair development and trap definition. This analysis integrates data from previously drilled wells and seismic data available to Kosmos. Importantly, this approach also takes into account a detailed analysis of geologic timing to ensure that we have an appropriate understanding of whether the sequencing of geological events could support and preserve hydrocarbon accumulation. Once an area is high-graded based on this play/fairway analysis, geophysical analysis is conducted to identify prospective traps of interest.

Alongside the subsurface analysis, Kosmos performs an analysis of country-specific risks to gain a comprehensive understanding of the "above-ground" dynamics, which may influence a particular country's relative desirability from an overall oil and natural gas operating and risk-adjusted return perspective. This iterative and comprehensive process is employed in both areas that have existing oil and natural gas production, as well as those regions that have yet to achieve commercial hydrocarbon production.

Once an area of interest has been identified, Kosmos actively targets licenses over the particular basin or fairway in order to achieve an early mover or in many cases a first-mover advantage. In terms of license selection, Kosmos targets specific regions that have sufficient size to provide scale should the exploration concept prove successful. Additional objectives include long-term contract duration to enable the "right" exploration program to be executed, play type diversity to provide multiple exploration concept options, prospect dependency to enhance the chance of replicating success and sufficiently attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons.

Operations by Geographic Area

We operate in the oil and gas exploration and production industry and have operations in Africa and South America. Currently, all revenues are generated from our operations offshore Ghana. Oil produced from West Africa, including the Jubilee Field, has generally priced in reference to Dated Brent crude. Brent crude is produced in the North Sea and is widely accepted by the oil and gas industry as the most representative of the global physical standards for the oil market in comparison to other reference oils, such as West Texas Intermediate ("WTI"). The location of the Jubilee Field offshore Ghana allows us to sell our oil to the major refining markets of North America, Asia and Europe. Due to its quality, oil from the Jubilee Field generally sells for a slight premium relative to Dated Brent.

Information about our discoveries and prospects are summarized below. In interpreting this information, general reference should be made to the risk factors as a whole and specific reference should be made to the subsections of this annual report on Form 10-K titled "Item 1A. Risk Factors—Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling," "Item 1A. Risk Factors—Under the terms of our various license agreements, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to declare any discoveries and thereby establish development areas may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects" and "Item 1A. Risk Factors—We are not, and may not be in the future, the operator on all of our license areas and do not, and may not in the future, hold all of the working interests in certain of our license areas.

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Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and to an extent, any non-wholly owned, assets."

Our Discoveries

Information about our discoveries is summarized in the following table.

Discoveries	License	Areal Extent (acres)	Kosmos Working Interest	Block Operator(s)	Stage	Type	Expected Year of PoD Submission
Ghana							
Jubilee Field Phase1(1)(2)	WCTP/DT(3)	8,300	24.0771%(5)	Tullow/Kosmos(6)	Production	Deepwater	2008(2)
Jubilee Field subsequent phases(1)(2)	WCTP/DT(3)	4,600	24.0771%(5)	Tullow/Kosmos(6)	Development	Deepwater	2011(7)
Mahogany East	WCTP(4)	6,600	30.8750%	Kosmos	Development planning	Deepwater	2011
Teak	WCTP(4)	23,000	30.8750%	Kosmos	Appraisal	Deepwater	2013
Akasa	WCTP(4)(8)	4,900	30.8750%	Kosmos	Appraisal	Deepwater	2014
Banda	WCTP(4)(8)	25,000	30.8750%	Kosmos	Appraisal	Deepwater	2014
Tweneboa	DT(4)(8)	27,000	18.0000%	Tullow	Appraisal	Deepwater	2013
Enyenra	DT(4)	28,100	18.0000%	Tullow	Appraisal	Deepwater	2012
Ntomme	DT(4)(8)	19,100	18.0000%	Tullow	Appraisal	Deepwater	2012

(1) For information concerning our estimated proved reserves in the Jubilee Field as of December 31, 2011, see "—Our Reserves."

(2) The Jubilee Phase 1 PoD was submitted to Ghana's Ministry of Energy in December 2008 and was formally approved in July 2009. The Jubilee Phase 1 PoD details the necessary wells and infrastructure to develop two of the reservoirs within the Jubilee Field. Oil production from the Jubilee Field offshore Ghana commenced on November 28, 2010, and we received our first oil revenues in early 2011. We intend to submit or amend PoDs for other reservoirs within the Jubilee Unit for the Jubilee Field subsequent phases to Ghana's Ministry of Energy for approval in order to extend the production plateau of the Jubilee Field, although we can give no assurance that such approvals will be forthcoming. See (7) below.

(3) The Jubilee Field straddles the boundary between the WCTP Block and the DT Block offshore Ghana. Consistent with the Ghanaian Petroleum Law, the WCTP Petroleum Agreement ("WCTP PA") and DT Petroleum Agreement ("DT PA") and as required by Ghana's Ministry of Energy, in order to optimize resource recovery in this field, we entered into the Unitization and Unit Operating Agreement (the "UUOA") in July 2009 with Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The UUOA governs the interests in and development of the Jubilee Field and created the Jubilee Unit from portions of the WCTP Block and the DT Block.

(4) GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block and the DT Block of 2.5% and 5.0%, respectively. In order to acquire the additional paying interest, GNPC must notify the contractor of its intention to acquire such interest within sixty to ninety days of the contractor's notice to Ghana's Ministry of Energy of a commercial discovery. These interest percentages do not give effect to the exercise of such options.

(5) These interest percentages are subject to redetermination of the working interests in the Jubilee Field pursuant to the terms of the UUOA. See "Item 1A. Risk Factors—The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result" and' —Significant Exploration Agreements—Jubilee Field Unitization." GNPC has exercised its WCTP PA and DT PA options, with respect to the Jubilee Unit, acquire an additional unitized paying interest of 3.64084% in the Jubilee Field. The Jubilee Field interest percentages give effect to the exercise of such option.

(6) Kosmos is the Technical Operator and Tullow Ghana Limited, a subsidiary of Tullow Oil plc ("Tullow"), is the Unit Operator of the Jubilee Unit. See " —Significant Exploration Agreements—Jubilee Field Unitization."

(7) The Jubilee Phase 1A PoD was submitted to Ghana's Ministry of Energy on December 18, 2011 and was formally approved in January 2012. The Jubilee Phase 1A PoD details the necessary wells and infrastructure to further develop the existing producing reservoirs and develop a third reservoir within the Jubilee Field.

(8) The areal extent for these discoveries were determined based on estimates derived internally by the Company and represents the possible upside areal extent for these discoveries. In future periods, should we have our independent petroleum engineers assess these discoveries, such estimates may change. Additionally, such estimates may change as a result of future assessment and appraisal activities. See Item 1A. Risk Factors—We face substantial uncertainties in estimating the characteristics of our unappraised discoveries and our prospects."

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Ghana Well Information

Information about the wells we have drilled on our license areas in Ghana is summarized in the following table.

	Operator	Spud Date(1)	Total Depth (feet)	Net Hydrocarbon Pay (feet)	Status(2)	Comments
Jubilee						
J-09 (Mahogany-1)	Kosmos	05/30/07	12,553	321	Producing	Discovery well for Jubilee in WCTP Block. Drill stem tested at rates in excess of 20,500 bopd. Lower completion installed.
Hyedua-1	Tullow	07/27/07	13,130	180	Plugged Back	Downdip confirmation well in DT Block.
J-10 Water Injector ("WI") (Hyedua-1BP1)	Tullow	07/27/07	12,631	136	Injecting	Whole core obtained. Injectivity test conducted at rates in excess of 20,000 bwpd. Down structure water injector.
J-16GI Gas Injectors ("GI") (Mahogany-2)	Tullow	03/06/08	11,296	164	Injecting	Updip confirmation well for Jubilee reservoirs. Whole core obtained. Updip gas injector.
J-08 (Hyedua-2)	Tullow	10/09/08	12,018	180	Producing	Drill stem tested at rates in excess of 16,500 bopd. Whole core obtained.
J-04	Tullow	01/17/09	15,121	90	Plugged Back	Tested the Southeastern edge of the Jubilee fairway.
J-04 Sidetrack ("ST")	Tullow	01/17/09	13,803	199	Producing	Observation well for interference testing.
J-01	Tullow	03/18/09	12,411	140	Producing	
J-02	Tullow	03/25/09	13,829	186	Producing	Observation well for interference testing.
J-11WI	Tullow	05/06/09	13,822	121	Injecting	Down structure water injector.
J-12WI	Tullow	05/11/09	14,081	188	Injecting	Down structure water injector.
J-15WI	Tullow	05/14/09	16,949	47	Injecting	Only drilled through Upper Mahogany—down structure water injector.
J-07	Tullow	05/19/09	13,599	121	Plugged Back	Whole core obtained.
J-07ST	Tullow	05/19/09	13,701	116	Plugged Back	
J-07ST2	Tullow	05/19/09	14,341	184	Producing	
J-03	Tullow	09/29/09	12,507	173	Producing	
J-05	Tullow	07/08/09	13,753	193	Producing	Lower completion installed.
J-17	Tullow	10/07/09	19,390	174	Plugged Back	Only drilled through Upper Mahogany reservoirs.
J-17STGI	Tullow	10/07/09	19,574	197	Injecting	Updip gas injector.
J-13WI	Tullow	10/10/09	13,058	143	Injecting	Down structure water injector.
J-14WI	Tullow	10/14/09	13,999	77	Injecting	Down structure water injector.
J-06	Tullow	04/13/11	12,959	147	Plugged back	
J-06ST1	Tullow	06/26/11	13,091	126	Producing	

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	Operator	Spud Date(1)	Total Depth (feet)	Net Hydrocarbon Pay (feet)	Status(2)	Comments
Mahogany East						
Mahogany-3	Kosmos	11/27/08	14,262	108	Suspended	Discovery well for Mahogany Deep.
Mahogany-4	Kosmos	08/28/09	12,074	141	Suspended	Updip confirmation well for the Mahogany East reservoirs.
Mahogany Deep-2	Kosmos	09/29/09	14,193	49	Suspended	Drilled to delineate deep reservoirs.
Mahogany-5	Kosmos	04/18/10	13,084	75	Suspended	Eastern confirmation of Mahogany East reservoirs.
Odum						
Odum-1	Kosmos	01/18/08	11,109	72	Abandoned	Discovery well for Odum. Subsequently not declared commercial.
Odum-2	Kosmos	11/12/09	8,222	66	Abandoned	Confirmation well for Odum. Subsequently not declared commercial.
Tweneboa						
Tweneboa-1	Tullow	01/26/09	13,002	69	Suspended	Discovery well for Tweneboa condensate pays.
Tweneboa-2	Tullow	12/06/09	13,878	105	Suspended	Confirmation well for Tweneboa. Discovery of Central Oil Channel below condensate pays. Whole core obtained.
Tweneboa-3	Tullow	11/26/10	12,811	29	Plugged back	Confirmation well for Tweneboa.
Tweneboa-3ST	Tullow	12/22/10	12,816	112	Suspended	Discovery well for Ntomme.
Tweneboa-4	Tullow	01/16/11	13,146	59	Suspended	Confirmation well for Tweneboa.
Onyina						
Onyina-1	Tullow	09/25/10		—	Abandoned	Dry hole.
Enyenra (formerly known as Owo)						
Owo-1	Tullow	06/10/10	12,766	174	Plugged Back	Discovery well for Enyenra.
Owo-1 ST1	Tullow	07/28/10	13,117	115	Suspended	Lateral confirmation well for Enyenra channels, and discovery wells for deeper condensate pays. Whole core obtained.
Owo-1 RA	Tullow	10/18/11	12,779	157	Suspended	
Enyenra-2	Tullow	01/22/11	13,887	121	Suspended	Downdip confirmation well for Enyenra channels. Discovery well for Tweneboa Deep.
Enyenra-3A	Tullow	04/20/11	13,205	56	Suspended	Updip confirmation well for Enyenra channels.
Teak						
Teak-1	Kosmos	12/21/10	10,398	239	Suspended	Discovery well for Teak.
Teak-2	Kosmos	02/12/11	11,184	89	Suspended	Drilled fault block adjacent to Teak-1 discovery.
Teak-3	Kosmos	10/6/11	10,571	115	Suspended	Northern extension of Teak discovery.
Dahoma						
Dahoma-1	Kosmos	02/04/10	14,403	—	Abandoned	Dry hole.

	Operator	Spud Date(1)	Total Depth (feet)	Net Hydrocarbon Pay (feet)	Status(2)	Comments
Banda						
Banda-1	Kosmos	03/31/11	15,026	10	Suspended	Discovery well for Banda. Well considered sub-commercial.
Makore						
Makore-1	Kosmos	04/25/11	12,717	—	Abandoned	Dry hole.
Akasa						
Akasa-1	Kosmos	07/13/11	12,856	108	Suspended	Discovery well for Akasa.
Ntomme						
Ntomme-2A	Tullow	11/09/11	13,156	128	Suspended	Confirmation for oil in Akasa discovery.

(1) In connection with our side-track wells, "spud date" refers to the date we commenced drilling such well.

(2) These terms have the following meanings:

Abandoned	Exploration / appraisal well that was deemed to have no further utility. The well was permanently abandoned, per approved government procedures.
Completion Pending	Production / Injection casing has been installed across the target interval as part of the normal drilling operations, and the well is scheduled / approved to have a completion installed to facilitate production / injection per the applicable PoD.
Injection Ready	Injection well has been drilled and completed. All well equipment is in place to commence injection.
Plugged Back	Well that has cement set across productive interval to facilitate production from sidetrack well.
Production Ready	Production well has been drilled and completed. All well equipment is in place to commence production.
Suspended	Exploration / appraisal well that has had production casing installed across the target interval. However, plans to utilize the well as part of a development have not yet been approved.

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Prospect Information

Information about our prospects on our license areas in Ghana, Cameroon and our Cap Boujdour Offshore license area in Morocco is summarized in the following table. We are currently assessing prospectivity on our recently acquired license areas in Morocco, Cameroon and Suriname and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, acquiring seismic information to assess the prospectivity for these license areas.

Prospect	License	Areal Extent (acres)	Kosmos Working Interest (%)	Block Operator	Type	Projected Spud Year(4)
Ghana(1)						
Cedrela	WCTP(5)(6)	3,400	30.875	Kosmos	Deepwater	2012
Odum East	WCTP(5)	3,100	30.875	Kosmos	Deepwater	Post 2012
Sapele	WCTP(5)	19,100	30.875	Kosmos	Deepwater	Post 2012
Funtum	WCTP(5)	6,700	30.875	Kosmos	Deepwater	Post 2012
Assin	WCTP(5)	2,600	30.875	Kosmos	Deepwater	Post 2012
Okoro	WCTP(5)	4,600	30.875	Kosmos	Deepwater	Post 2012
Late Cretaceous WCTP Play (4 identified targets)	WCTP(5)	8,100	30.875	Kosmos	Deepwater	Post 2012
Turonian Deep	DT	23,000	18.000	Tullow	Deepwater	2012
DT Sapele	DT	4,600	18.000	Tullow	Deepwater	2012
Wawa	DT	9,100	18.000	Tullow	Deepwater	2012
Walnut	DT	2,900	18.000	Tullow	Deepwater	Post 2012
Wassa	DT	8,900	18.000	Tullow	Deepwater	Post 2012
Adinkra	DT	1,300	18.000	Tullow	Deepwater	Post 2012
Oyoko	DT	1,900	18.000	Tullow	Deepwater	Post 2012
Ananta	DT	1,600	18.000	Tullow	Deepwater	Post 2012
Cameroon(2)						
Sipo (formerly known as Liwenyi)	Ndian River	4,000	100.000	Kosmos	Onshore	2012
Liwenyi South	Ndian River	1,600	100.000	Kosmos	Onshore	Post 2012
Meme	Ndian River	3,800	100.000	Kosmos	Onshore	Post 2012
Bamusso	Ndian River	12,100	100.000	Kosmos	Onshore	Post 2012
Morocco(3)						
	Cap Boujdour					Post

Gargaa	Offshore	13,900	75.000	Kosmos	Deepwater	2012
Argane	Cap Boujdour Offshore	11,600	75.000	Kosmos	Deepwater	Post 2012
Safsaf	Cap Boujdour Offshore	22,400	75.000	Kosmos	Deepwater	Post 2012
Aarar	Cap Boujdour Offshore	8,100	75.000	Kosmos	Deepwater	Post 2012
Zitoune	Cap Boujdour Offshore	10,000	75.000	Kosmos	Deepwater	Post 2012
Al Arz	Cap Boujdour Offshore	13,400	75.000	Kosmos	Deepwater	Post 2012
Felline	Cap Boujdour Offshore	13,500	75.000	Kosmos	Deepwater	Post 2012
Nakhil	Cap Boujdour Offshore	6,500	75.000	Kosmos	Deepwater	Post 2012
Barremian Tilted Fault Block Play (8 identified structures)	Cap Boujdour Offshore	49,400	75.000	Kosmos	Deepwater	Post 2012

(1) GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block and the DT Block of 2.5% and 5.0%, respectively. In order to acquire the additional paying interests, GNPC must notify the contractor of its intention to do so within sixty to ninety days of the contractor's notice to Ghana's Ministry of Energy of a commercial discovery. These interest percentages do not give effect to the exercise of such options.

(2) The Republic of Cameroon has an option to acquire an interest of up to 15.0% in a commercial discovery on the Ndian River Block. These interest percentages do not give effect to the exercise of such options. The table does not include the license information for the Fako Block in Cameroon, which we entered into in January 2012.

(3) We have not yet made a decision as to whether or not to drill our Morocco prospects within the Cap Boujdour Offshore Block. If we decide to continue into the drilling phase of the license, we anticipate that the first well to drill within the Cap Boujdour Offshore Block will be post 2012.

(4) See "Item 1A. Risk Factors—Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling" and "Item 1A. Risk Factors—Under the terms of our various license agreements, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to declare any discoveries and thereby establish development areas may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects."

(5) In July 2011, at the end of the seven-year exploration phase, parts of the WCTP Block, which include these prospects, were subject to relinquishment. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to these areas. We and our WCTP Block partners exercised such right in July 2010 and formally submitted a new petroleum agreement for such areas in early October 2011. We and our WCTP Block partners, the Ghana 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 these areas. See "—Ghana."

(6) We have disputed the relinquishment of the area around the Cedrela prospect. See "—Ghana" and "Item 1A. Risk Factors—We had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements."

Ghana

The WCTP and DT Blocks are located within the Tano Basin, offshore Ghana. This basin contains a proven world-class petroleum system as evidenced by our discoveries.

The Tano Basin represents the eastern extension of the Deep Ivorian Basin which resulted from the development of an extensional sedimentary basin caused by tensional forces associated with opening of the Atlantic Ocean, as South America separated from Africa in the mid-Cretaceous period. The Tano Basin forms part of the resulting transform margin which extends from Sierra Leone to Nigeria.

The Tano Basin sediments comprise a thick Upper Cretaceous, deepwater turbidite sequence which, in combination with a modest Tertiary section, provided sufficient thickness to mature an early to mid-Cretaceous source rock in the central part of the Tano Basin. This well-defined reservoir and charge fairway forms the play which, when draped over the South Tano high (a structural high dipping into the basin) resulted in the formation of trapping geometries.

The primary prospect types consist of well imaged Turonian and Campanian aged submarine fans situated along the steeply dipping shelf margin and trapped in an up dip direction by thinning of the reservoir and/or faults. Many of our discoveries have similar trap geometries.

Kosmos is the operator of the WCTP Block and holds a 30.9% participating interest. 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 (Akasa, Banda, Mahogany

East and Teak) have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase. 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 operations 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 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. See "Item 1A. Risk Factors—We had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements."

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 Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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.

Kosmos holds a non-operated 18.0% participating interest in the DT Block. The DT PA, which governs our activities relating to the DT Block, has a duration of 30 years from its effective date. The seven-year exploration phase of the DT PA will expire in January 2013. Our existing discoveries within the DT Block (Tweneboa, Enyenra and Ntomme) are not subject to relinquishment upon expiration of the exploration phase of the DT PA, as the DT PA remains in effect after the end of the exploration phase. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum contract and certain rights to negotiate a new petroleum contract with respect to areas of the DT Block that are subject to relinquishment under the DT PA; that is acreage not within a discovery area, development and production area or the Jubilee Unit ("DT Relinquishment Area"). We and our DT Block partners exercised such right to negotiate a new petroleum contract in January 2012.

One of our DT Block partners, Sabre Oil and Gas Limited ("Sabre"), provided notice that it intends to transfer all of its 4.05% participating interest in the DT Block to a third party for approximately $365.0 million, with up to $45.0 million in contingent payments upon achieving certain performance milestones. Under the DT Joint Operating Agreement, each of the DT Block partners have a right of first refusal regarding the transfer of such interest to a third party, assuming the block partner is willing to match the terms and conditions of the existing offer of the third party. On February 23, 2012, we exercised our right to accept the terms and conditions of the proposed transfer. Subject to Government of Ghana consent, we anticipate the transaction to close during the second quarter of 2012. After the acquisition, our interest in the DT Block and Jubilee Unit will increase to 22.05% and 25.82258%, respectively.

Our Ghanaian Discoveries

The following is a brief discussion of our discoveries to date on our license areas offshore Ghana. See "Item 1A. Risk Factors—We face substantial uncertainties in estimating the characteristics of our unappraised discoveries and our prospects."

Jubilee Discovery

The Jubilee Field was discovered by Kosmos in 2007 within the WCTP Block. An appraisal well was subsequently drilled in the offsetting DT Block, confirming a large accumulation of oil underlying areas within both blocks. The Jubilee Field is located approximately 37 miles (60 kilometers) offshore Ghana in water depths of 3,250 to 5,800 feet (991 to 1,707 meters). Pursuant to the terms of the UUOA, the discovery area was unitized for purposes of joint development by the WCTP and DT Block participating interest holders. The UUOA specifies a split operatorship role. Kosmos was the Technical Operator for Development and Tullow was designated as the Unit Operator. The initial tract participations were 50% for each block. Pursuant to the terms of the Jubilee Field UUOA, the percentage is subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.36660% 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 "Item 8. Financial Statements and Supplementary Data—Note 5—Joint Interest Billings") to 24.07710%. See "Item 1A. Risk Factors—The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result."

The Jubilee Field is a combination structural-stratigraphic trap with reservoir intervals consisting of a series of stacked Upper Cretaceous Turonian-aged, deepwater turbidite fan lobe and channel deposits.

The location of the Jubilee Field led to the decision to implement an FPSO based development plan. The "Kwame Nkrumah" FPSO has a design capacity of processing approximately 120,000 bopd of oil, 160,000 Mcfpd of natural gas, and storing up to 1.6 Mmbbl of stabilized crude. Further, the vessel can provide water and natural gas injection of 232,000 bwpd and 160,000 Mcfpd, respectively, to support reservoir pressure. The Phase 1 development focused on partial development of certain reservoirs in the Jubilee Field. The Kosmos-led integrated project team successfully executed an initial 17 well development plan, which included nine producing wells, six water injection wells and two natural gas injection wells, the FPSO and subsea infrastructure. This initial phase provided infrastructure capacity for additional production and injection wells that could potentially be drilled in future phases of development. Future phases include the further development of the existing producing reservoirs and development of the three remaining reservoirs to maximize ultimate recovery.

The Jubilee Unit partners are currently performing remediation efforts on certain of the producing wells in the Phase 1 development. Optimized completion techniques are being implemented which are expected to mitigate the near wellbore productivity issues experienced in certain wells.

The Jubilee Field Phase 1A development at Jubilee was approved in 2012 by the Government of Ghana. The Phase 1A development began in 2012 and is expected to include eight new wells, including five production wells and three water injection wells, as well as an expanded subsea infrastructure.

WCTP Block Discoveries

The Mahogany East area is located within the WCTP Block, southeast of the Jubilee Field. The field is approximately 37 miles (60 kilometers) offshore Ghana in water depths of 4,101 to 5,905 feet (1,250 to 1,800 meters). We believe the field is a combination stratigraphic-structural trap with reservoir intervals contained in a series of stacked Upper Cretaceous Turonian-aged, deepwater fan lobe and channel deposits. The Mahogany-3, Mahogany-4, Mahogany-5 and Mahogany Deep-2 wells have intersected multiple oil bearing reservoirs in a Turonian turbidite sequence. Fluid samples recovered from the wells indicate an oil gravity of between 31 and 37 degrees API.

The Mahogany East 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, 2011. In a letter dated May 16, 2011, the Minister 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, the Ministry of Energy, 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 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 approval of the Mahogany East 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. We and the WCTP Block partners are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

The Teak discovery is located in the western portion of the WCTP Block, northeast of the Jubilee Field. The field is approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 650 to 3,600 feet (200 to 1,100 meters). We believe the field is a structural-stratigraphic trap with an element of four-way closure. The Teak-1, Teak-2 and Teak-3 wells have intersected multiple oil and natural gas condensate bearing reservoirs in Campanian and Turonian zones. Fluid samples recovered from the wells indicate an oil gravity of between 32 and 39 degrees API and natural gas condensate gravity of between 40 and 45 degrees API.

The Akasa discovery is located in the western portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 3,200 to 5,050 feet (950 to 1,550 meters). The discovery is southeast of the Jubilee Field. We believe the target reservoirs are channels and lobes that are stratigraphically trapped. The Akasa-1 well intersected oil bearing reservoirs in the Turonian zones. Fluid samples recovered from the well indicate an oil gravity of 38 degrees API.

The Banda discovery is located in the southeastern portion of the WCTP Block. The field is approximately 27 miles (43 kilometers) offshore Ghana in water depths of approximately 1,800 to 4,900 feet (550 to 1,500 meters). We believe the target reservoir is a channel fairway that is stratigraphically trapped. The Banda-1 well intersected quantities of oil-bearing reservoirs in Cenomanian to Albian zones, although the well is considered sub-commercial. The Banda discovery represents a new play in the WCTP Block.

Following additional appraisal, drilling and evaluation, a decision regarding the commerciality of these discoveries on the WCTP Block will be made by the WCTP Block partners. Should a discovery be declared commercial, a PoD would be prepared for submission to Ghana's Ministry of Energy within six months of the declaration of commerciality.

DT Block Discoveries

The Tweneboa discovery is located in the central portion of the DT Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 3,281 to 5,252 feet (1,000 to 1,500 meters). We believe the field is a stratigraphic trap with reservoir intervals contained within a series of stacked Upper Cretaceous Turonian-aged, deepwater turbidite fan lobes and channel deposits. The Tweneboa-1, Tweneboa-2, Tweneboa-3, Tweneboa-3ST and Tweneboa-4 wells have intersected multiple natural gas condensate and oil bearing reservoirs in this Turonian turbidite sequence. Fluid samples recovered from the wells indicate an oil gravity of approximately 31 degrees API and a natural gas condensate gravity of between 41 and 47 degrees API.

The Enyenra discovery is located in the Western portion of the DT Block. The field is approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 3,300 to 5,000 feet (1,000 to 1,500 meters). We believe the field is primarily a stratigraphic trap with reservoir intervals contained within a series of stacked Upper Cretaceous Turonian-aged, deepwater channel deposits. The Owo-1, Owo-1 ST1, Owo-1RA, Enyenra-2A and Enyenra-3A wells have intersected multiple oil and natural gas condensate bearing reservoirs in a Turonian turbidite sequence. Fluid samples recovered from the wells indicate an approximate oil gravity of 32 degrees API, and a natural gas condensate gravity of between 42 and 48 degrees API. We believe Enyenra is predominantly an oil accumulation.

The Ntomme discovery is located in the central portion of the DT Block. The field is approximately 32 miles (52 kilometers) offshore Ghana in water depths of approximately 3,950 to 5,700 feet (1,200 to 1,750 meters). We believe the field is a stratigraphic trap with reservoir intervals contained within a series of stacked Upper Cretaceous Turonian-aged, deepwater fan lobes and channel deposits. The Tweneboa-3ST well discovered the Ntomme discovery and the Ntomme-2A appraisal well confirmed a downdip extension of the field. The wells encountered high-quality stacked reservoir sandstones. The Ntomme-2A confirmed the majority of the resources in the discovery to be oil. Fluid samples recovered from the wells indicate an oil gravity of 35 degrees API.

The Tweneboa Deep discovery is located in the southern portion of the DT Block approximately 44 miles (70 kilometers) offshore Ghana in water depths of approximately 4,900 to 5,900 feet (1,500 to 1,800 meters). We believe the field comprises a north-south trending Upper Cretaceous Lower Turonian aged turbidite system. The Enyenra-2A well discovered Tweneboa Deep while testing a deeper Turonian fan where natural gas-condensate bearing sandstones were intersected. Fluid sampling from the Enyenra-2A well indicates an approximate natural gas condensate gravity of 46 degrees API. Pursuant to the terms of the DT PA, in September 2011, the operator notified the Ministry of Energy that the discovery did not at that time merit appraisal but that further studies would be performed prior to making a final decision on appraisal.

Following additional appraisal, drilling and evaluation, a decision regarding the commerciality of these discoveries on the DT Block will be made by the DT Block partners. Should a discovery be declared commercial, a PoD would be prepared for submission to Ghana's Ministry of Energy within six months of the declaration of commerciality.

Our Ghanaian Prospects

WCTP Block

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 Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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. The following is a brief discussion of our prospects in the WCTP Relinquishment Area, should a new petroleum agreement be entered into for the WCTP Relinquishment Area.

Cedrela

Cedrela located in the southern most part of the WCTP block, approximately 42 miles (67 kilometers) offshore Ghana in water depths of approximately 4,950 to 5,650 feet (1,500 to 1,700 meters). It is located approximately three miles from the Dahoma-1 well and is defined by a high resolution seismic survey. The Cedrela prospect consists of Turonian through Albian sediments trapped within a fair way closure. See "Item 1A. Risk Factors—We had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporationregarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements."

Odum East

Odum East is located in the eastern portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 2,600 to 3,300 feet (800 to 1,000 meters). It is located 1.9 miles (3 kilometers) east of the Odum-1 and Odum-2 well penetrations and defined by a high resolution 3D seismic data survey as a combination structural-stratigraphic trap, and is very similar to the Odum discovery. The target interval is comprised of Upper Cretaceous Campanian aged stacked turbidite sequences. The first well to drill Odum East is anticipated to be spud post 2012.

Sapele

Sapele is located in the northern portion of the WCTP Block approximately 22 miles (35 kilometers) offshore Ghana in water depths of approximately 300 to 2,600 feet (100 to 800 meters). It targets an Upper Cretaceous Middle Campanian age system of amalgamated channels forming an extensive depositional system with associated facies confining the width of the stratigraphic trap to approximately 6.2 miles (10 kilometers) wide. High resolution 3D seismic information indicates the presence of submarine fan channels. The first well to drill Sapele is anticipated to be spud post 2012.

Funtum

Funtum is located in the northern portion of the WCTP Block approximately 22 miles (35 kilometers) offshore Ghana in water depths of approximately 300 to 1,600 feet (100 to 500 meters). It targets an Upper Cretaceous Middle Campanian age confined channel system approximately 1.3 miles (2 kilometers) wide with associated channel margin facies extending the stratigraphic trap to approximately 3.1 miles (5 kilometers) wide. High resolution 3D seismic information indicates the presence of a prospective submarine fan. The first well to drill Funtum is anticipated to be spud post 2012.

Assin

Assin is located in the central portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 2,600 to 3,300 feet (800 to 1,000 meters). It is approximately 2.5 miles (4 kilometers) northwest and updip of the Odum discovery. The stratigraphic trap is defined by a high resolution 3D seismic survey and is very similar in nature to the Odum discovery. The target interval is comprised of Upper Cretaceous, Campanian aged stacked turbidite sequences interlayered with marine shale. The first well to drill Assin is anticipated to be spud post 2012.

Okoro

Okoro is a tilted Albian fault block located in the central portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 2,600 to 3,000 feet (800 to 900 meters). It sits adjacent to the Jubilee field but in older and deeper stratigraphy. Oil samples from deeper wells within Tano Basin have also recovered oil samples from Albian formations. The first well to drill Okoro is anticipated to be spud post 2012.

Late Cretaceous WCTP Play

Four additional Late Cretaceous targets are present on the WCTP Block offshore Ghana in water depths from 600 to 4,300 feet (190 to 1,300 meters). These targets range in age from Cenomanian to Campanian. They comprise four-way closures to stratiographic channel traps. If a target matures into a prospect, the first well to drill one of these targets is anticipated to be spud post 2012.

DT Block

The following is a brief discussion of our prospects in the DT Block.

DT Sapele

DT Sapele is located in the eastern portion of the DT Block approximately 37 miles (60 kilometers) offshore Ghana in water depths of approximately 5,250 to 5,900 feet (1,600 to 1,800 meters). The target reservoir is a down-dip extension of the Upper Cretaceous Turonian age sand fairway at Jubilee. The combination structural stratigraphic reservoir is well defined with high resolution 3D seismic and well information from the surrounding Jubilee and Mahogany East discoveries. The first well to drill DT Sapele is expected to be spud in 2012.

Wawa

The Wawa prospect is located in the north central part of the DT block, approximately 21 miles (35 kilometers) offshore Ghana in water depths of approximately 650 to 3,350 feet (200 to 1,000 meters). The prospect has been defined with high resolution seismic data. The Wawa prospect comprises of Upper Cretaceous Campanian and Turonian reservoirs. The traps for the reservoirs within the prospect area are combination structural and stratigraphic traps. The well is anticipated to spud in 2012.

Tweneboa Deep (also known as Turonian Deep)

The Turonian Deep prospect is located in the southern central part of the DT block, approximately 33 miles (53 kilometers) offshore Ghana in water depths of approximately 4,400 to 6,450 feet (1,325 to 2,000 meters). The prospect has been defined by high resolution seismic data and consists of Turonian and Cenomanian sediments that are trapped stratigraphically within the reservoir fairway. The well is anticipated to spud in 2012.

Walnut

Walnut is located along the northern edge of the DT Block approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 1,600 to 2,600 feet (500 to 800 meters). It targets stratigraphic and downthrown fault closures varying in age from Turonian to Campanian. The first well to drill Walnut is anticipated to be spud post 2012.

Wassa

Wassa is located in the south central portion of the DT Block approximately 44 miles (70 kilometers) offshore Ghana in water depths of approximately 5,900 to 6,200 feet (1,800 to 1,900 meters). It has a trapping geometry at multiple levels from Albian through Turonian with a stratigraphic trap element and a large three-way fault trap at the Albian level. The first well to drill Wassa is anticipated to be spud post 2012.

Adinkra

Adinkra is located along the northern edge of the DT Block approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 1,600 to 2,600 feet (500 to 800 meters). It targets stratigraphic and downthrown fault closures varying in age from Turonian to Campanian. The first well to drill Adinkra is anticipated to be spud post 2012.

Oyoko

Oyoko is located along the northern edge of the DT Block approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 1,600 to 2,600 feet (500 to 800 meters). It targets stratigraphic and downthrown fault closures of Albian to Cenomanian age. The first well to drill Oyoko is anticipated to be spud post 2012.

Ananta

Ananta is located in the western portion of the DT Block approximately 37 miles (60 kilometers) offshore Ghana in water depths of approximately 4,300 to 5,250 feet (1,300 to 1,600 meters). It is a stratigraphic trap of Campanian age located west of the existing Tweneboa wells. The Tweneboa-1 well encountered thick porous sands at this interval. Ananta contains similar facies as detected through AVO analysis. The first well to drill Ananta is anticipated to be spud post 2012.

Cameroon

During 2011, Kosmos had interests in two licenses in Cameroon, the Ndian River Block located in the Rio del Rey Basin, which we operate with a 100% participating interest, and the Perenco operated, Kombe-N'sepe Block located in the Douala Basin, in which Kosmos held a 35% interest. The Kombe-N'sepe license expired on December 31, 2011, as the Company did not exercise our option to extend the license period. The Ndian River Block is located in the eastern, onshore and shallow water offshore portion of the Rio del Rey Basin.

Kosmos is currently in the first of two available extensions of the exploration period of our Ndian River Block, which expires in November 2012. The current exploration period carries a one-well obligation and Kosmos is currently performing pre-drilling activities with plans to commence drilling in late 2012. The Ndian River petroleum contract provides for an extension of an exploration phase for a period of time that the Minister of Industry, Mines and Technology Development deems necessary to complete any exploration drilling in progress at the end of the exploration phase, with this extended period being at least six months. Current plans call for drilling activities to be in progress at the end of the current exploration phase and as such, we plan to apply for the extension in accordance with the petroleum contract and the regulations in force.

Cameroon sits in the Gulf of Guinea adjacent to and south of the Niger Delta. The coastal and offshore portions of Cameroon are associated with two major but different geological basins. In the north and adjacent to the Niger delta is the Rio del Rey Basin. In addition to the oil province, there is a large outboard natural gas condensate province containing the Alba field.

In January 2012, Kosmos entered into a license with Cameroon for the Fako Block. Kosmos is the operator and has a 100% participating interest in the block. The block covers 318,519 acres(1,289 square kilometers) and borders the southeast portion of our Ndian River Block in the Rio del Rey Basin. We have $2.0 million in work commitments to perform exploration activities.

To date, Kosmos has acquired gravity, magnetic and 2D seismic data over selected portions of our Cameroon licenses. We have drilled two exploration wells which discovered hydrocarbons in sub-commercial quantities, which were subsequently plugged and abandoned in the Kombe-N'sepe Block.

Our Cameroon Prospects

The following is a brief discussion of our onshore Cameroon prospects on the Ndian River Block. We are currently assessing prospectivity on our recently acquired Fako Block license area, and accordingly information concerning prospects, if any, on such recently acquired license area is not yet available. We currently are, and plan to continue, acquiring seismic information to assess the prospectivity for this license area.

Sipo (formerly known as Liwenyi)

Sipo is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a large structurally trapped anticline associated with multiple stacked targets within the Miocene Isongo Formation. Sipo is located in the heart of the Isongo reservoir fairway which constitutes primary reservoir in the Alba and Esmeraldas fields in Equatorial Guinea and in Bowleven's recent IF and IE oil and natural gas condensate discoveries in the Etinde Block to the south. Sipo is also situated along trend from the Etinde Block discoveries and in a similar trap type. An exploration well is anticipated to be drilled late in 2012.

Liwenyi South

Liwenyi South is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a structurally trapped anticline associated with multiple stacked targets within the Miocene Isongo Formation. Liwenyi South is located in the next thrust sheet south from Sipo. It is located in the heart of the Isongo reservoir fairway, which constitutes primary reservoir in the Alba and Esmeraldas Fields in Equatorial Guinea and in the recent IF and IE oil and natural gas condensate discoveries in the Etinde Block to the south. Liwenyi South is also situated along trend from the Etinde Block discoveries and in a similar trap type. An exploration well is anticipated to be drilled post 2012.

Meme

Meme is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a faulted three-way closure trapped on the downthrown side of a three-way trapping fault and is comprised of several targets within the Miocene Isongo Formation. Meme is located along trend with the Alba and Esmeraldas Fields in Equatorial Guinea. An exploration well is scheduled to be drilled post 2012.

Bamusso

Bamusso is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a fault trap within the Upper Cretaceous section. An exploration well is anticipated to be drilled post 2012.

Morocco

During 2011, Kosmos pursued an acreage acquisition program offshore the Kingdom of Morocco and by year-end had acquired two new petroleum contracts, renewed an existing petroleum contract and acquired a new reconnaissance contract. Our exploration licenses include Cap Boujdour Offshore Block, which is within the Aaiun Basin, and Essaouira Offshore Block and Foum Assaka Offshore Block, which are within the Agadir Basin. Our reconnaissance contract is over the Tarhazoute Offshore area within the Agadir Basin.

Kosmos is the operator of the Cap Boujdour Offshore Block and has a 75% participating interest. This block is located within the Aaiun Basin, along the Atlantic passive margin and covers a high-graded area within the original Boujdour Offshore Block which expired in February 2011. Detailed seismic sequence analysis suggests the possible existence of stacked deepwater turbidite systems throughout the region. The scale of the license area has allowed us to identify multiple distinct exploration fairways on this block, each having independent play risks, providing substantial exploration opportunities. Based in part on a 3D seismic survey, we have been able to identify prospect inventory through trap identification, detailed structural analysis, and depositional history mapping. See "Item 1A. Risk Factors—A portion of our asset portfolio is in Western Sahara, and we could be adversely affected by the political, economic and military conditions in that region. Our exploration licenses in this region conflict with exploration licenses issued by the Sahrawai Arab Democratic Republic."

Kosmos is the operator of the Foum Assaka Offshore Block and has a 37.5% participating interest. Upon receipt of approval from the Moroccan government, we will acquire an additional 18.75% in the Foum Assaka Offshore Block from Pathfinder Hydrocarbon Ventures Ltd., one of our block partners. Kosmos is the operator of the Essaouira Offshore Block and has a 37.5% participating interest.

Kosmos is the operator and holder of a reconnaissance contract covering the Tarhazoute Offshore area and has a 100% interest. The Tarhazoute Offshore area is located offshore Morocco in the Agadir Basin between the Company's Essaouira and Foum Assaka Offshore Blocks. The reconnaissance contract has a one-year term, extendable for an additional six months, after which the Company has the right to enter into a petroleum contract for the acreage.

The Foum Assaka Offshore Block, Essaouira Offshore Block, and Tarhazoute Offshore area are located in the Agadir Basin. The Agadir Basin sediments comprise thick sequences of Lower to Upper Cretaceous sequences consisting of channels and lobes. A working petroleum system has been established in the basin based on onshore and shallow offshore wells.

In our new license areas, we have $12.5 million, of which some was incurred in 2011, in work commitments to perform exploration activities. We are currently acquiring 3D seismic data on the Foum Assaka Offshore and Essaouira Offshore Blocks and may drill an exploratory well in Morocco as early as 2013.

Our Moroccan Prospects

The following is a brief discussion of our prospects on the Cap Boujdour Offshore Block. We are currently assessing prospectivity on our recently acquired license areas in Morocco, and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, acquiring seismic information to assess the prospectivity for these license areas.

Gargaa

Gargaa is located offshore in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 5,250 to 6,500 feet (1,600 to 2,000 meters). It is one of four large four-way closures which sit on a 328 mile (100 kilometer) long anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 3D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Argane

Argane is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 4,600 to 6,000 feet (1,400 meters to 1,800 meters). It is one of four large four-way closures which sit on a 328 mile (528 kilometers) long anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 3D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Safsaf

Safsaf is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 8,200 to 9,500 feet (2,500 to 2,900 meters). It is a large four-way closure with a stratigraphic trapping element located over a anticline and containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 3D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Aarar

Aarar is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 6,500 to 8,500 feet (2,000 to 2,600 meters). It is one of four, large, four-way closures which sit on a 328 mile (528 kilometer) long compressional anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Zitoune

Zitoune is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 6,250 to 7,500 feet (1,900 to 2,300 meters). It is one of four, large, four-way closures which sit on a 328 mile (528 kilometer) long anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

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Al Arz

Al Arz is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 1,300 to 2,000 feet (400 to 600 meters). It is a large, three-way fault closure on the upthrown side of a three-way trapping fault containing multiple stacked targets within the Early Cretaceous Hauterivian through Albian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Felline

Felline is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 7,200 to 7,900 feet (2,200 to 2,400 meters). It is a large, four-way closure containing multiple stacked targets within the Early Cretaceous through Albian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Nakhil

Nakhil is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 3,600 to 4,250 feet (1,100 to 1,300 meters). It is a large, four-way closure containing multiple stacked targets within the Early Cretaceous through Albian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Barremian Tilted Fault Block Play

An additional eight prospects have been defined on our existing 2D and 3D seismic database; these consist of a variety of three-way fault closures with targets in the Early Cretaceous age. Exploration wells are anticipated to be drilled post 2012.

Suriname

Kosmos' new ventures effort extended beyond our historical West Africa focus area as we entered into two petroleum contracts in South America. In December 2011, Kosmos entered into petroleum contracts covering Block 42 and Block 45 offshore Suriname. Kosmos is the operator and has a 100% participating interest in both blocks.

Our blocks in Suriname are located within the Guyana-Suriname Basin, along the Atlantic passive margin of northern South America. The basin resulted from rock deformation caused by tensional forces associated with the opening of the Atlantic Ocean, as South America separated from Africa in the mid-Cretaceous period. This basin has experienced the same geologic forces which occurred along the transform margin of Africa and, therefore, we believe the basin's petroleum system to be analogous to petroleum systems seen in West Africa. A petroleum system in Suriname has been proven by the presence of onshore producing fields.

In our new license areas, we have $13.7 million in work commitments to perform exploration activities. We plan to acquire 3D seismic data in our blocks offshore Suriname in 2012 to further define prospectivity on the blocks.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2011. See "Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Data (Unaudited)" for additional information.

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All of our estimated proved reserves as of December 31, 2011 were attributable to the Jubilee Field in Ghana.

Summary of Oil and Gas Reserves as of December 31, 2011

	Net Proved Reserves(1)		
	Oil, Condensate, NGLs (Mmbbl)	Natural Gas(2) (Bcf)	Total (Mmboe)
Reserves Category			
Proved developed	23	16	26
Proved undeveloped	25	8	26
	47	24	51

(1) Kosmos' unitized net interest is based on the 54.3666/45.6334% redetermination split, between the WCTP Block and DT Block. See "Item 1A. Risk Factors—The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result." Totals within the table may not add due to rounding.

(2) These reserves represent only the quantities of fuel gas required to operate the FPSO during normal field operations. No natural gas volumes, outside of the fuel gas reported, have been classified as reserves. If and when a gas sales agreement is executed, a portion of the remaining gas may be reclassified as reserves. See "Item 1A. Risk Factors—We may not be able to commercialize our interests in any natural gas produced from our license areas."

All of our proved undeveloped reserves ("PUDs") at December 31, 2011, 2010 and 2009, were associated with our Jubilee Field in Ghana.

Changes for the year ending December 31, 2011, include an increase of 8 Mmbbl of proved undeveloped oil reserves due to the reclassification of some of the proved developed producing volumes to proved undeveloped for volumes related to the remediation efforts to mitigate the near wellbore productivity issues on certain of the producing wells in the Jubilee Field and an increase in our Jubilee Field unit interest. Additional changes include an increase of 4 Bcf in proved undeveloped gas reserves due to an increase in our Jubilee Field unit interest (see "Item 8. Financial Statements and Supplementary Data—Note 4—Jubilee Field Unitization") and an increase in the estimated gas reserves to be used as fuel gas for operating the FPSO.

Changes for the year ending December 31, 2010, include a decrease of 35 Mmbbl of proved undeveloped oil reserves, associated with reclassification to proved developed, resulting from first oil in the Jubilee Field on November 28, 2010. Additional changes include an increase of 4 Bcf, associated with the booking of gas reserves to be utilized as fuel gas for operating the FPSO.

The following table sets forth the estimated future net revenues, excluding derivatives contracts, from net proved reserves and the expected benchmark prices used in projecting net revenues at December 31, 2011.

	Projected Net Revenues (in Millions except $/bbl)
Future net revenues	$ 2,850
Present value of future net revenues:	
PV-10(1)	2,016
Future income tax expense (levied at a corporate parent and intermediate subsidiary level)	—
Discount of future income tax expense (levied at a corporate parent and intermediate subsidiary level) at 10% per annum	—
Standardized Measure(2)	2,016
Benchmark and differential oil price($/bbl)(3)	$ 111.04

(1) PV-10 represents the present value of estimated future revenues to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, royalties, additional oil entitlements and future tax expense levied at an asset level (in our case, future Ghanaian tax expense levied under the WCTP and DT PAs), using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10% to reflect the timing of future cash flows. PV-10 is a non-GAAP financial measure and often differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of future income tax expense related to proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level on future net revenues. However, it does include the effects of future tax expense levied at an asset level (in our case, it does include the effects of future Ghanaian tax expense levied under the WCTP and DT PAs). Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas assets. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP; however, we and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific corporate tax characteristics of such entities.

(2) Standardized Measure represents the present value of estimated future cash inflows to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, future income tax expense related to our proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level, royalties, additional oil entitlements and future tax expense levied at an asset level (in our case, future Ghanaian tax expense levied under the WCTP and DT PAs), without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10% to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure often differs from PV-10 because Standardized Measure includes the effects of future income tax expense related to our proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level on future net revenues. However, as we had been a tax

exempted company incorporated pursuant to the laws of the Cayman Islands and are now a tax exempted company incorporated pursuant to the laws of Bermuda pursuant to our corporate reorganization that was completed in our IPO in May 2011, and as the Company's intermediate subsidiaries positioned between it and the subsidiary that is a signatory to the WCTP and DT PAs will continue to be tax exempted companies, we have not been and do not expect to be subject to future income tax expense related to our proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level on future net revenues. Therefore, the year-end 2011 estimate of PV-10 is equivalent to the Standardized Measure.

(3) The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months was $111.02/bbl for Dated Brent at December 31, 2011. The price was adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the high quality of the crude, these adjustments are estimated to add a $0.02/bbl premium relative to Dated Brent. This differential is utilized in our reserve estimates. The adjusted price utilized to derive the PV-10 is $111.04/bbl.

Estimated proved reserves

Unless otherwise specifically identified in this report, the summary data with respect to our estimated proved reserves presented above has been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent reserve engineering firm, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities and adjusted for imbalances. These rules require SEC reporting companies to prepare their reserve estimates using reserve definitions and pricing based on 12-month historical unweighted first-day-of-the-month average prices, rather than year-end prices. For a definition of proved reserves under the SEC rules, see the "Glossary and Selected Abbreviations." For more information regarding our independent reserve engineers, please see "—Independent petroleum engineers" below.

Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil, without giving effect to derivative transactions, and were held constant throughout the life of the assets.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2011 are based on costs in effect at December 31, 2011 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the fiscal year ending December 31, 2011, adjusted for anticipated market premium, without giving effect to derivative transactions, and are held constant throughout the life of the assets. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. See "Item 1A. Risk Factors—The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves."

Independent petroleum engineers

NSAI, our independent reserve engineers, was established in 1961. Over the past 50 years, NSAI has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, acquisition and divestiture evaluations, simulation studies, exploration resources assessments, equity determinations, and management and advisory services. NSAI professionals subscribe to a code of professional conduct and NSAI is a Registered Engineering Firm in the State of Texas.

For the years ended December 31, 2011, 2010 and 2009, we engaged NSAI to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our reserves and related future net revenues and PV-10 for the periods indicated therein. Our estimated reserves at December 31, 2011and related future net revenues and PV-10 at December 31, 2011 are taken from reports prepared by NSAI, adjusted for imbalances, in accordance with petroleum engineering and evaluation principles which NSAI believes are commonly used in the industry and definitions and current regulations established by the SEC. The December 31, 2011 reserve report was completed on February 16, 2012, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2011, 2010 and 2009 reserves reports, NSAI prepared its own estimates of our proved reserves. In the process of the reserves evaluation, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI which brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. NSAI independently prepared reserves estimates to conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(2) of Regulation S-X. NSAI issued a report on our proved reserves at December 31, 2011, based upon its evaluation. NSAI'sprimary economic assumptions in estimates included an ability to sell oil at a price of $111.04/bbl, a certain level of capital expenditures necessary to complete the Jubilee Field development program and the exercise of GNPC's back-in right on the Jubilee Field development. The assumptions, data, methods and precedents were appropriate for the purpose served by these reports, and NSAI used all methods and procedures as it considered necessary under the circumstances to prepare the report.

Technology used to establish proved reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have proved effective by actual comparison of production from projects in the same reservoir interval, an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, production and injection data, electrical logs, radioactivity logs, acoustic logs, whole core analysis, sidewall core analysis, downhole pressure and temperature measurements, reservoir fluid samples, geochemical information, geologic maps, seismic data, well test and interference pressure and rate data. Reserves attributable to undeveloped locations were estimated using performance from analogous wells with similar geologic depositional environments, rock quality, appraisal plans and development plans to assess the estimated ultimate recoverable reserves as a function of the original oil in place. These qualitative measures are benchmarked and validated against sound petroleum reservoir engineering principles and equations to estimate the ultimate recoverable reserves volume. These techniques include, but are not limited to, nodal analysis, material balance, and numerical flow simulation.

Internal controls over reserves estimation process

In our technical services team, we currently maintain an internal staff of eight petroleum engineering and geoscience professionals with significant international experience that contribute to our Reserve and Resource Reporting Process. This team works closely with NSAI to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserve and resource estimation process. Our technical services team is responsible for overseeing the preparation of our reserves estimates. Our technical services team has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team holds a Bachelor of Science degree in petroleum engineering. The NSAI technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Joseph J. Spellman and Mr. Daniel T. Walker. Mr. Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (No. 73709) and has over 30 years of practical experience in petroleum engineering. He graduated from University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. Walker has been practicing consulting petroleum geology at NSAI since 1993. Mr. Walker is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1272) and has over 30 years of practical experience in petroleum geoscience. He graduated from Michigan State University in 1980 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Audit Committee reviews our Reserves and Resource Reporting Process on an annual basis. In addition, our technical team meets with representatives of our independent reserve engineers to review our assets and discuss methods and assumptions used in preparation of the reserve and resource estimates. Finally, our senior technical/operations management and senior technical staff review reserves and reserve estimates with representatives from our independent reserve engineers.

For the years ended December 31, 2011, 2010 and 2009, we engaged NSAI, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties. See "—Independent petroleum engineers" above for further information regarding NSAI's report.

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License Areas

The following table sets forth certain information regarding the developed and undeveloped portions of our license areas as of December 31, 2011 for the countries in which we currently operate.

	Developed Area (Acres)		Undeveloped Area (Acres)		Total Area (Acres)	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)
			(In thousands)			
Ghana						
Jubilee Unit	27.1	6.3	—	—	27.1	6.3
West Cape Three Points(2)	—	—	170.6	52.7	170.6	52.7
Deepwater Tano	—	—	190.1	34.2	190.1	34.2
Cameroon(4)						
Ndian River	—	—	434.2	434.2	434.2	434.2
Morocco(3)						
Cap Boujdour	—	—	7,349.1	5,511.8	7,349.1	5,511.8
Essaouira	—	—	2,898.7	1,087.0	2,898.7	1,087.0
Foum Assaka	—	—	1,599.5	599.8	1,599.5	599.8
Suriname						
Block 42	—	—	1,526.1	1,526.1	1,526.1	1,526.1
Block 45	—	—	1,266.7	1,266.7	1,266.7	1,266.7
Total	27.1	6.3	15,435.0	10,512.5	15,462.1	10,518.8

(1) Net acreage based on Kosmos' working interest, before the exercise of any options or back-in rights. Our net acreage may be affected by any redetermination of interests in the Jubilee Unit. See "Item 1A. Risk Factors—The unit partners' respective interests in the Jubilee Unit are subjec to redetermination and our interests in such unit may decrease as a result."

(2) The seven-year exploration phase of the WCTP PA expired on July 21, 2011. WCTP "Undeveloped Area" reflected in the table above represents acreage within the four discovery areas (Teak, Banda, Akasa and Mahogany East) that were not subject to relinquishment on the expiry of the exploration phase, WCTP Undeveloped Area reflected in the table above includes the development and production Area relating to the Mahogany East PoD, which is the subject of a Notice of Dispute with the Ministry of Energy and GNPC and is currently under discussion with the WCTP Block partners, GNPC and the Ministry of Energy (see "—Our Ghanaian Discoveries—WCTP Block Discoveries"). Additionally, the WCTP Undeveloped Area in the table above includes acreage within the area relating to the Cedrela prospect, that was to be drilled by the Cedrela-1 exploration well; but which is the subject of a Notice of Force Majeure and a Notice of Dispute with the Ministry of Energy and GNPC and is currently under discussion among the Company, GNPC and the Ministry of Energy.

(3) Does not include the reconnaissance contract for the Tarhazoute area offshore the Kingdom of Morocco as we do not currently have a license for this area. This block covers 1,915,932 gross acres (7,754 square kilometers) and is located offshore in the Agadir Basin immediately between our Essaouria Offshore and Foum Assaka Offshore Blocks.

(4) Does not include the petroleum contract for the Fako Block in Cameroon, which we entered into in January 2012. The block covers 318,519 acres (1,289 square kilometers) and borders the southeast portion of our Ndian River Block in the Rio del Rey Basin.

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Drilling activity

The results of oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Exploratory and Appraisal Wells(1)						Development Wells							
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total		Total	Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Net	Gross
Year Ended December 31, 2011														
Ghana														
Jubilee Unit	—	—	—	—	—	—	1	0.24	—	—	1	0.24	0.24	1
West Cape Three Points	—	—	4	1.24	4	1.24	—	—	—	—	—	—	1.24	4
Deepwater Tano	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cameroon														
Kombe-N'sepe	—	—	1	0.35	1	0.35	—	—	—	—	—	—	0.35	1
Total	—	—	5	1.59	5	1.59	1	0.24	—	—	1	0.24	1.83	6
Year Ended December 31, 2010														
Ghana														
Jubilee Unit	—	—	—	—	—	—	1	0.24	—	—	1	0.24	0.24	1
West Cape Three Points	—	—	1	0.31	1	0.31	—	—	—	—	—	—	0.31	1
Deepwater Tano	—	—	1	0.18	1	0.18	—	—	—	—	—	—	0.18	1
Cameroon														
Kombe-N'sepe	—	—	1	0.35	1	0.35	—	—	—	—	—	—	0.35	1
Total	—	—	3	0.84	3	0.84	1	0.24	—	—	1	0.24	1.08	4
Year Ended December 31, 2009														
Ghana														
Jubilee Unit	—	—	—	—	—	—	11	2.59	—	—	11	2.59	2.59	11
West Cape Three Points	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Deepwater Tano	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	11	2.59	—	—	11	2.59	2.59	11

(1) As of December 31, 2011, 16 exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have foundproved reserves. These wells are shown as "Wells Suspended or Waiting on Completion" in the table below.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.

(3) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be a productive well, as opposed to the year the well was drilled.

The following table shows the number of wells that are in the process of being drilled or are in active completion stages, and the number of wells suspended or waiting on completion as of December 31, 2011:

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	1	0.24	—	—	—	—
West Cape Three Points	—	—	—	—	8	2.47	—	—

Deepwater Tano	2	0.36	—	—	8	1.44	—	—
Total	2	0.36	1	0.24	16	3.91	—	—

Undeveloped license area expirations

The WCTP PA 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, the WCTP Relinquishment Area was subject to relinquishment. 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 East 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 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 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. See "Item 1A. Risk Factors—We had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements."

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 Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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.

The Mahogany East 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, 2011. In a letter dated May 16, 2011, the Minister 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, Ministry of Energy, 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 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 approval of the Mahogany East 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. We and the WCTP Block partners are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

In the DT Block in Ghana, the first extension period of the exploration phase over the undeveloped acreage of the DT Block expired on January 19, 2011. In accordance with the DT PA, Tullow, on behalf of the DT Block partners, formally extended the DT PA into the second extension period and relinquished 25% of the DT Block. The seven-year exploration phase of the DT PA will expire in January 2013. Our existing discoveries within the DT Block are not subject to relinquishment upon expiration of the exploration phase of the DT PA, as the DT PA remains in effect after the end of the exploration phase, and these are Tweneboa, Enyenra and Ntomme. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum contract and certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area. We and our DT Block partners exercised such right to negotiate a new petroleum contract in January 2012.

In Cameroon, under the Ndian River Production Sharing Contract and pursuant to a one-year extension approved by the Ministry of Industry, Mines, and Technological Development, the initial exploration phase to the Ndian River Block expired on November 19, 2010. On September 16, 2010, in compliance with the production sharing contract, we applied to Cameroon's Minister of Industry, Mines and Technology Development for a two-year renewal of the exploration period (the first of two additional exploration periods of two years each). On November 20, 2010, in accordance with the Ndian River Production Sharing Contract, Kosmos relinquished 30% of the original license area of the Ndian River Block and entered into the first two-year renewal period. In an order dated March 3, 2011, the Minister of Industry, Mines and Technology Development confirmed our entry into the first renewal period.

The Kombe-N'sepe License Agreements over the Kombe-N'sepe Block in Cameroon expired on December 31, 2011, after a previous six month extension was granted.

Domestic Supply Requirements

Many of our petroleum contracts or, in some cases, the applicable law governing such agreements, grant a right to the respective host country to purchase certain amounts of oil produced pursuant to such agreements at international market prices for domestic consumption. In addition, in connection with the approval of the Jubilee Phase 1 PoD, the Jubilee Field partners agreed to provide the first 200 Bcf of natural gas produced from the Jubilee Field Phase 1 development to GNPC at no cost. See "Item 1A. Risk Factors—Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets or delay our oil and natural gas production."

Significant Exploration Agreements

West Cape Three Points Block

Effective July 22, 2004, Kosmos, the EO Group and GNPC entered into the WCTP PA covering the WCTP Block offshore Ghana in the Tano Basin. Kosmos held an initial 86.5% working interest in the block. Pursuant to farm-out agreements for the WCTP Block dated September 1, 2006, Anadarko WCTP Company, Tullow andSabre farmed into the WCTP Block. Subsequent to the initial farm-out agreements, Tullow acquired EO Group. As a result, Kosmos, Anadarko WCTP Company, Tullow and Sabre's participating interests are 30.875%, 30.875%, 26.396% and 1.854%, respectively. Kosmos is the operator. GNPC has a 10% participating interest and will be carried through the exploration and development phases. Under the WCTP PA, GNPC exercised its option in December 2008 to acquire an additional paying interest of 2.5% in the Jubilee Field development (see "—Jubilee Field Unitization"). GNPC is obligated to pay its 2.5% share of all future petroleum costs as well as certain historical development and production costs attributable to its 2.5% additional paying interests in the Jubilee Unit. Furthermore, it is obligated to pay 10% of the production costs of the Jubilee Field development, as allocated to the WCTP Block. In August 2009, GNPC notified us and our unit partners it would exercise its right for the contractor group to pay its 2.5% WCTP Block share of the Jubilee Field development costs and be reimbursed for such costs plus interest out of GNPC's production revenues under the terms of the WCTP PA. Kosmos is required to pay a fixed royalty of 5% and a sliding-scale royalty ("additional oil entitlement") which escalates as the nominal project rate of return increases. These royalties are to be paid in-kind or, at the election of the Government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level.

The WCTP Block as originally awarded comprised approximately 483,599 acres (1,957 square kilometers). Due to contractual relinquishments at the commencement of contract periods, the WCTP Block currently comprises areas that are part of our existing discoveries in the WCTP Block, or approximately 182,417 acres (738 square kilometers) in water depths ranging from 165 to 5,900 feet(approximately 50 to 1,800 meters). The term of the WCTP PA is 30 years from the effective date of such agreement, being July 22, 2004. The initial exploration period of the block is three years, divided into two separate 18-month subperiods. In 2005, a 268,109 acre (1,085 square kilometers) 3D seismic survey was acquired, processed and interpreted by Kosmos. In 2006, Kosmos elected to proceed with the second subperiod with an exploration well commitment. The exploration well, Mahogany-1, was drilled and an oil discovery announced on June 18, 2007. The work and financial commitments were met for the initial exploration period. The next phase, the first extension period, commenced at the end of the initial exploration period and was for two years. The one exploration well commitment for this period was met by drilling the Odum-1 well, which tested a different prospect than the Mahogany-1 well. Odum-1 was announced as an oil discovery on February 25, 2008. In July 2009, Kosmos elected to enter the second and final two year extension period under the WCTP PA. The commitment for this period was met by drilling of the Dahoma-1 well, which tested a different prospect from those tested by Mahogany-1 and Odum-1. All work and financial obligations for the exploration periods under the WCTP PA have been met.

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 Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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.

Deepwater Tano Block

Effective July 31, 2006, Kosmos, Tullow and Sabre entered into the DT PA with GNPC covering the DT Block offshore Ghana in the Tano Basin. Tullow is the operator with a 49.95% working interest. Sabre has a 4.05% working interest. Kosmos originally held a 36% working interest in the block; however, as a result of a farmout by Kosmos to Anadarko WCTP Company effective September 1, 2006, Kosmos and Anadarko WCTP Company each have an 18% participating interest in the block. GNPC has a 10% participating interest and will be carried through the exploration and development phases. Under the DT PA, GNPC exercised its option in January 2009 to acquire an additional paying interest of 5% in the commercial discovery with respect to the Jubilee Field development. GNPC is obligated to pay its 5% of all future petroleum costs, including development and production costs attributable to its 5% additional paying interest. Furthermore, it is obligated to pay 10% of the production costs of the Jubilee Field development, as allocated to the DT Block. In August 2009, GNPC notified us and our unit partners that it would exercise its right for the contractor group to pay its 5% DT Block share of the Jubilee Field development costs and be reimbursed for such costs plus interest out of a portion of GNPC's production revenues under the terms of the DT PA. Kosmos is required to pay a fixed royalty of 5% and an additional oil entitlement which escalates as the nominal project rate of return increases. These royalties are to be paid in-kind or, at the election of the Government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level.

The DT Block comprises approximately 203,345 acres (823 square kilometers). The term of the DT PA is 30 years from the effective date of such agreement, July 31, 2006. The initial exploration period is two and one-half years, divided into two subperiods. The first subperiod was for one year, and the contractor was obligated to reprocess 3D seismic data and acquire seabed logging. This commitment was met and the block partners entered the second subperiod. During the second subperiod of one and one-half years, the contractor was required to drill an exploration well, which was fulfilled by the drilling of the Tweneboa-1 exploration well. During December 2008, the block partners notified Ghana's Ministry of Energy of their intent to enter into the first extension period of two years commencing on January 19, 2009. During the first extension period of two years, the contractor was required to drill an exploration well, which was fulfilled by the drilling of the Owo-1 exploration well. During December 2010, the block partners notified Ghana's Ministry of Energy of their intent to enter into the second extension period of two years commencing on January 19, 2011. During the second extension period of two years, the contractor was required to drill an exploration well, which was fulfilled by the Onyina-1 exploration well, drilled during the first extension period. The DT PA provides that work performed in excess of that required to meet the obligations of an exploration period can be applied to obligations in a subsequent period and this was done. Also, the DT PA provides that if the contractor commits to the drilling of two or more wells during the second extension period, the mandatory acreage relinquishment is reduced from 50% to 25%. The contractor made this commitment in its notification of entry into the second extension period. Currently, the contractor must drill one additional exploration well prior to the end of the exploration period to fulfill the obligation, which is expected to be drilled in 2012.

The Ghanaian Petroleum Law and the WCTP and DT PAs form the basis of our exploration, development and production operations on these blocks. Pursuant to these petroleum agreements, most significant decisions, including PoDs and annual work programs, for operations other than exploration and appraisal, must be approved by a joint management committee, consisting of representatives of certain block partners and GNPC. Certain decisions require unanimity. See "Item 1A. Risk Factors—We are not, and may not be in the future, the operator on all of our license areas and do not, and may not in the future, hold all of the working interests in certain of our license areas. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and to an extent, any non-wholly owned, assets."

Jubilee Field Unitization

The Jubilee Field, discovered by the Mahogany-1 well in June 2007, covers an area within both the WCTP and DT Blocks. Consistent with the Ghanaian Petroleum Law, the WCTP and DT PAs and as required by Ghana's Ministry of Energy, it was agreed the Jubilee Field would be unitized for optimal resource recovery. In late February 2008, the contractors in the WCTP and DT Blocks agreed to an interim unit agreement (the "Pre Unit Agreement"). According to the Pre Unit Agreement, the initial Jubilee Field unit area, which boundary at the time was an approximation of the boundaries of the Jubilee Field, was deemed to consist of 35% of an area from the WCTP Block and 65% of an area from the DT Block. However, the tract participations were allocated 50% for the WCTP Block and 50% for the DT Block pending the results of the Mahogany-2 well. The Mahogany-2 well was announced as an oil discovery on May 5, 2008. Pursuant to the Pre Unit Agreement, the unit boundaries were modified to include the Mahogany-2 well and the tract participations remained 50% for each block.

Kosmos and its unit partners subsequently commenced development operations and negotiated a more comprehensive unit agreement, the UUOA, for the purpose of unitizing the Jubilee Field and governing each party's respective rights and duties in the Jubilee Unit. On July 13, 2009, Ghana's Ministry of Energy provided its written approval of the UUOA. The UUOA was executed by the unit partners and was effective as of July 16, 2009. Tullow is the Unit Operator, while Kosmos is the Technical Operator for Development of the Jubilee Unit. The Jubilee Unit holders' interests are subject to redetermination subject to the terms of the UUOA. See "Item 1A. Risk Factors—The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result." The accounting for the Jubilee Unit is in accordance with the tract participation stated in the UUOA, adjusted for the initial redetermination process as discussed above. Although the Jubilee Field is unitized, Kosmos' working interests in each block outside the boundary of the Jubilee Unit remains the same. Kosmos remains operator of the WCTP Block outside the Jubilee Unit area. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.36660% 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—see "Item 8. Financial Statements and Supplementary Data—Note 5—Joint Interest Billings") to 24.07710%.

We, as the Technical Operator, led the Integrated Project Team ("IPT"), which consisted of geoscience, engineering, commercial, project services, and operations disciplines from within the Jubilee Unit partnership. The Technical Operator evaluated the resource base and developed an optimized reservoir depletion plan. This plan included the design and placement of wells and the selection of topside and subsea facilities. The Technical Operator's responsibilities also extended to project management of the design and implementation of the complete field development system. The Unit Operator was responsible for drilling and completing the development wells for the Jubilee Field Phase 1 development, according to the specifications outlined by the IPT, and providing other in-country support. Upon first production, the Unit Operator assumed responsibility for the day-to-day operations and maintenance of the FPSO as well as overseeing and optimizing the reservoir management plan based on field performance, including any well workover activity or additional infill drilling. The responsibility of the Technical Operator and the IPT for the Jubilee Field Phase 1 development was completed upon commissioning of the gas compression and injection systems and project administrative close out.

On July 13, 2009, Ghana's Ministry of Energy provided its written approval of the Jubilee Phase 1 PoD. First oil from the Jubilee Field Phase 1 development commenced on November 28, 2010, and we received approval from Ghana's Ministry of Energy for the Jubilee Field Phase 1A development in January 2012. We intend to submit a Jubilee Full Field development plan in late 2013.

Ndian River Block

On December 19, 2006, Kosmos signed the Ndian River Production Sharing Contract covering the Ndian River Block located predominately onshore Cameroon. Kosmos has a 100% participating interest in the block and is the operator. Société Nationale des Hydrocarbures ("SNH") will be carried through the exploration and appraisal phases and has the option to back into the contract with an interest of up to 15% upon approval of a PoD. The Ndian River Production Sharing Contract provides for Kosmos to recover its share of expenses incurred ("cost recovery oil") and its share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 60% of gross revenue prior to profit oil being split between the government of Cameroon and the contractor. Profit oil is then apportioned based upon "R-factor" tranches, where the R-factor is cumulative net revenues divided by cumulative net investment. A corporate tax rate of 40% is applied to profits. The initial period of the exploration phase is three years and there are two renewal periods of two years with each carrying a one-well obligation. The Ndian River Block comprises approximately 434,163 acres (approximately 1,757 square kilometers) and occupies a coastal strip of the Rio del Rey Basin in northwestern Cameroon. The block is located about 62 miles (100 kilometers) west-northwest of the city of Douala and extends to the Cameroon/Nigeria border. The license commitment requires us to conduct a 2D seismic survey (subject to a $5.5 million maximum spend commitment) as part of the multi-year exploration and exploitation agreement. Because of delays caused by difficulties in conducting seismic operations during the rainy season, the survey commenced in November 2009, causing a portion of the survey to be acquired beyond the initial exploration phase end date of November 19, 2009. In recognition of this, we, in consultation with SNH and Cameroon's Ministry of Industry, Mines and Technology Development, agreed to a process for receiving an extension to the initial period. On November 16, 2009, we received Ministry approval of a one year extension to the initial period of the exploration phase, which ended on November 19, 2010. A 2D seismic survey of 52 miles (85 kilometers) has been acquired in the block and interpretation of the survey is ongoing. On September 16, 2010, in accordance with the terms of the Ndian River Production Sharing Contract and after fulfillment of all the obligations of the initial period, we submitted an application for entry into the first of two renewal periods of the exploration phase with an attendant one-well obligation. We plan to drill a well on the Ndian River Block in late 2012. Planning for this well is ongoing.

Sales and Marketing

Production from the Jubilee Field began on November 28, 2010, and we received our first oil revenues in early 2011. As providedunder the UUOA and the WCTP and DT PAs, we are entitled to lift and sell our share of the Jubilee production in conjunction with the Jubilee Unit partners. We have entered an agreement with an oil marketing agent to market our share of the Jubilee Field oil on the international spot market, and we approve the terms of each sale proposed by such agent. Oil from the Jubilee Field has generally sold at a premium to Dated Brent. We do not anticipate entering into any long term sales agreements at this time.

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.

Competition

The oil and gas industry is competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring and developing licenses. Many of these competitors have financial and technical resources and personnel compliments substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and natural gas assets, or to evaluate, bid for and purchase a greater number of licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful wells, sustained periods of volatility in financial and commodities markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which may adversely affect our competitive position.

We are also affected by competition for drilling rigs and the availability of related equipment. Higher commodity prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. In recent years, oil and natural gas companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill wells and conduct our operations.

Competition is also strong for attractive oil and natural gas producing assets, undeveloped license areas and drilling rights, and we cannot assure holders of our common shares that we will be able to successfully compete when attempting to make further strategic acquisitions.

Title to Property

Other than as specified in this annual report on Form 10-K, we believe that we have satisfactory title to our oil and natural gas assets in accordance with standards generally accepted in the international oil and gas industry. Our licenses are subject to customary royalty and other interests, liens under operating agreements and other burdens, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of, or affect the carrying value of, our interests. For examples, see "Item 1A. Risk Factors—A portion of our asset portfolio is in Western Sahara, and we could be adversely affected by the political, economic and military conditions in that region. Our exploration licenses in this region conflict with exploration licenses issued by the Sahrawai Arab Democratic Republic" and "Item 1A. Risk Factors—Maritime boundary demarcation between Côte D'Ivoire and Ghana may affect a portion of our license areas." and "Item 1. Business—Operations by Geographic Area, Ghana."

Environmental Matters

General

We and our operations are subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use and transportation of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various permits before operations commences;
- enjoin some or all of the operations of facilities deemed not in compliance with permits;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require remedial measures to mitigate or remediate pollution from our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws can be costly; the regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. We cannot assure you that we have been or will be at all times in compliance with such laws, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

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

For example, the Macondo spill in the Gulf of Mexico (described in "Item 1A. Risk Factors—Participants in the oil and gas industry are subject to numerous laws that can affect the cost, manner or feasibility of doing business") has resulted and will likely continue to result in increased scrutiny and regulation in the United States. The governments of the countries in which we currently, or in the future may, operate may also impose increased regulation as a result of this or similar incidents, which could materially delay or prevent our operations in those countries.

Climate Change

Our operations and the combustion of petroleum and natural-gas based products results in the emissions of greenhouse gases ("GHGs") that could contribute to global climate change. Climate change regulation has gained some momentum in recent years internationally and at the federal, regional, state and local levels in the United States. On the international front, various nations, including countries in which we have petroleum contracts, have committed to reducing their GHG emissions pursuant to the Kyoto Protocol, which is set to expire in 2012. Passage of a successor international agreement or scheme aimed at the reduction of GHGs is uncertain.

In December 2009, an international meeting was held in Copenhagen, Denmark to further progress towards a new international treaty or agreement regarding GHG emissions reductions after 2012. A number of countries, including countries in which we have petroleum contracts, entered into the Copenhagen Accord, which represents a broad political consensus that reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and contains non-binding emissions reductions targets. Further discussions towards an agreement took place in Cancun, Mexico at the end of 2010 and Durban, South Africa in December 2011. The Durban conference resulted in, among other things, an agreement to negotiate a new climate change regime by 2015 that would aim to cover all major GHG emitters worldwide, and take effect by 2020. In addition, the Durban conference resulted in the relevant parties agreeing to extend the Kyoto Protocol for a second commitment period. Any treaty or other arrangement ultimately adopted by any of the countries in which we have operations or otherwise do business may increase our compliance costs, such as for monitoring or reducing emissions, and may have an adverse impact on the global supply and demand for oil and natural gas, which could have a material adverse impact on our business or results of operations.

Furthermore, the physical effects of climate change could have an adverse effect on our operations through increased severity and frequency of weather events, including storms, floods and other events, which could increase costs to repair and maintain our facilities or delay or prevent our operations. If such effects were to occur, they could have an adverse effect on our exploration and production operations, or disrupt transportation or other process-related services provided by our third party contractors.

Oil Spill Response

Kosmos has developed and adopted an Oil Spill Contingency Plan ("OSCP") for the coordination of responses to oil spills arising from its operations in Ghana, including the WCTP Block. In addition, Tullow maintains an OSCP covering the Jubilee Field and DT Block. Both plans are based on the principle of "Tiered Response" to oil spills ("Guide to Tiered Response and Preparedness", IPIECA Report Series, Volume 14, 2007). A Tier 1 spill is defined as a small-scale operational incident which can be addressed with resources that are immediately available to Kosmos. A Tier 2 spill is a larger incident which would need to be addressed with regionally based shared resources. A Tier 3 spill is a large incident which would require assistance from national or world wide spill co-operatives. Under the OSCPs, emergency response teams may be activated to respond to oil spill incidents. We maintain a tiered response system for the mobilization of resources depending on the severity of an incident. Approximately 130 personnel (composed primarily of Tullow and Kosmos employees, Ghanaian Navy personnel and local contractors) have been trained on the assembly and operation of Tier 1 and Tier 2 onshore, nearshore and harbor response equipment. In the case of a Tier 3 incident, we engage the services of Oil Spill Response Limited ("OSRL") of Southampton, United Kingdom, an oil spill response contractor.

Our associate membership with OSRL entitles us to utilize its oil spill response services comprising technical expertise and assistance, including access to response equipment and dispersant spraying systems. Kosmos does not own any oil spill response equipment. Instead, Kosmos and Tullow each maintain separate lease agreements with OSRL for Tier 1 and Tier 2 packages of oil spill response equipment. Tier 1 equipment, which is stored in "ready to go trailers" for effective mobilization and rapid deployment, includes booms and ancillaries, recovery systems, pumps and delivery systems, oil storage containers, personal protection equipment, sorbent materials, hand tools, containers and first aid equipment. Tier 2 equipment consists of larger boom and oil recovery systems, pump and delivery systems and auxiliary equipment such as generators and lighting sets, and is also containerized and pre-packed in trailers and ready for quick mobilization.

As Unit Operator for the Jubilee Field, Tullow has additional response capability to handle an offshore Tier 1 response. Further, our membership in the West and Central Africa Aerial Surveillance and Dispersant Spraying Service gives us access to aircraft for surveillance and spraying of dispersant, which is administered by OSRL for a Tier 2 offshore response. The aircraft is based at the Kotoka International Airport in Accra, Ghana with a contractual response time, fully loaded with dispersant, of six hours. Additional stockpiles of dispersant are maintained in Takoradi.

In the case of a Tier 3 event, our associate membership in OSRL provides us with access to the large stockpile of equipment in Southampton, United Kingdom along with access to additional dispersant spraying aircraft. Kosmos could hire additional resources such as boats, earth moving equipment and personnel as necessary to respond to such an event. While we have the above in place, we can make no assurance, that these resources will be available or timely respond as intended, perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons.

Per common industry practice, under the agreements currently in place governing the terms of use of the drilling rigs used by us or our block partners, the drilling rig contractors indemnify us and our block partners in respect of pollution and environmental damage arising out of operations which originate above the surface of the water and from a drilling rig contractor's property, including, but not limited to, their drilling rig and other related equipment. Furthermore, pursuant to the terms of the operating agreements covering the blocks in which we or our block partners are currently drilling, except in certain circumstances, each block partner is responsible for the share of liabilities in proportion to its respective working interest in the block incurred as a result of pollution and environmental damage, containment and clean-up activities, loss or damage to any well, loss of oil or natural gas resulting from a blowout, crater, fire, or uncontrolled well, loss of stored oil and natural gas, and liabilities incurred in connection with plugging or bringing under control any well. Kosmos maintains insurance coverage for an incident concerning a well that results in pollution and environmental damage. The amount of annual insurance coverage maintained is proportional to our interest in a given well; with our current annual well control coverage for Ghana being $300 million per incident multiplied by our working interest in a well for well control, re-drilling, pollution, clean up and containment, excess of retention of $5 million multiplied by our working interest. In addition we maintain annual third party liability coverage of $300 million multiplied by our working interest in a well for third party liabilities including pollution coverage, environmental damages liabilities and/or claims made by or on behalf of third party individuals in the event of such party's bodily injury, death or property damage. For example, if there were a well blowout in the Jubilee Field (in which we have a 26.85484% development working interest) our limit of well control, redrill and pollution clean up and containment coverage would be 26.85484% of $300 million (being $80.6 million) excess of retention of 26.85484% of $5 million (being $1.3 million), and our limit of liability coverage including pollution liability would be 26.85484% of $300 million (being $80.6 million).

Other Regulation of the Oil and Gas Industry

Ghana

The Ghanaian Petroleum Law currently governs the upstream Ghanaian oil and natural gas regulatory regime and sets out the policy and framework for industry participants. All petroleum found in its natural state within Ghana is deemed to be national property and is to be developed on behalf of the people of Ghana. GNPC is empowered to carry out exploration and development work either on its own or in partnership with local or foreign partners. Companies who wish to gain rights to explore and produce in Ghana can only do so by entering into a petroleum agreement with Ghana and GNPC. The law requires for the terms of the petroleum agreement to be negotiated and agreed between GNPC and oil and gas companies. The Parliament of Ghana has final approval rights over the negotiated petroleum agreement. Ghana's Ministry of Energy represents the state in its regulatory capacity. GNPC has rights to undertake petroleum operations in any acreage declared open by Ghana's Ministry of Energy and has a carried interest in each petroleum agreement and is typically increased by a certain agreed upon amount at the option of GNPC following the declaration of any commercial discovery. Petroleum agreements are required to include certain domestic supply requirements, including the sale to Ghana of oil for consumption in Ghana at international market prices.

The Ghanaian Petroleum Law and our Ghanaian petroleum agreements contain provisions restricting the direct or indirect assignment or transfer of such petroleum agreements or interests thereunder without the prior written consent of GNPC and the Ministry of Energy. The Petroleum Law also imposes certain restrictions on the direct or indirect transfer by a contractor of shares of its incorporated company in Ghana to a third party without the prior written consent of Ghana's Minister of Energy. The Ghanaian Tax Law may impose certain taxes upon the direct or indirect transfer of interests in the petroleum agreements or interests thereunder.

Ghana's Parliament is considering the enactment of a new Petroleum Exploration and Production Act and has enacted a new Petroleum Revenue Management Act and the Petroleum Commission Act 2011. The new Petroleum Exploration and Production Act remains in a draft form, with industry comments having been submitted. The new Petroleum Revenue Management Act of 2011 pertains primarily to the collection, allocation, and management by the Government of Ghana of the petroleum revenue. The Petroleum Commission Act creates the Petroleum Commission, whose objective is to regulate and manage the use of petroleum resources and coordinate the policies thereto. The Petroleum Commission became effective in January 2012. Among the Petroleum Commission's functions are advising the Minister of Energy on matters such as field development plans, recommending to the Minister national policies related to petroleum, and storing and managing data. We understand the primary purpose of the Petroleum Commission is to fulfill the regulatory functions previously undertaken by GNPC. We anticipate a period of transition as the Petroleum Commission becomes active. We currently believe that such laws will only have prospective application, and as such will not modify the terms of (or interests under) the agreements governing our license interests in Ghana, including the WCTP and DT PAs (which include stabilization clauses) and the UUOA, and will not impose additional restrictions on the direct or indirect transfer of our license interests, including upon a change of control. See "Item 1A. Risk Factors—Participants in the oil and gas industry are subject to numerous laws that can affect the cost, manner or feasibility of doing business."

Cameroon

In 1999/2000, the government of Cameroon approved the Petroleum Code (the "Cameroon Petroleum Code") and Petroleum Regulations that were designed to rationalize regulation of the upstream local oil and gas industry. The Cameroon Petroleum Code applies to all license awards granted post 2000. Arrangements entered into prior to 2000 are grandfathered under the former law. Companies who wish to gain rights to explore and produce in Cameroon can only do so by entering into a petroleum contract with Cameroon, represented by SNH, the Cameroon national oil company, and assignments of such contracts require the consent of the government. SNH, established in March 1980, participates in the form of joint ventures with the "contractors." Assignment of license interests requires the consent of SNH.

Morocco

The two main legislative acts in Morocco relevant to petroleum exploration and production are (i) the Law 21-90 (1 April 1992) as amended and completed by the Law 27-99 (15 February 2000) and (ii) the Decree 2-93-786 (3 November 1993) as amended and completed by decree 2-99-210 (16 March 2000) (together, "Morocco's Petroleum Laws"). The regulatory authority in Morocco is the Ministry of Energy, Mines, Water and Environment and the national oil company acting on his behalf is the *Office National des Hydrocarbures et des Mines* generally referred to as "ONHYM." ONHYM is a public establishment (*établissement public*) with the legal personality and financial autonomy created pursuant to the Law 33-01 (11 November 2003) which was further completed by the Decree 2-04-372 (29 December 2004).

Pursuant to the Law 21-90, it is provided that the granting of an exploration permit is subject to the conclusion of a petroleum agreement with the Moroccan State. Therefore, companies who wish to gain rights to explore and produce in Morocco can only do so by entering into a petroleum contract with ONHYM acting on behalf of the State. It is further provided that the State of Morocco (via ONHYM) shall retain a participation in exploration permits or exploitation concessions which shall not be in excess of 25%. More generally, ONHYM is representing the State of Morocco for licensing, exploration and exploitation matters within the limit of its prerogatives set out pursuant to the Law 33-01. Assignments of percentage interests in field developments also require the consent of the administration pursuant to the Law 21-90.

The Sahrawai Arab Democratic Republic (the "SADR") has claimed sovereignty over the Western Sahara territory, including the area offshore, and has issued exploration licenses which conflict with those issued by Morocco, including certain licenses which conflict with the Cap Boujdour Offshore license issued to Kosmos. See "Item 1A. Risk Factors—A portion of our asset portfolio is in Western Sahara, and we could be adversely affected by the political, economic, and military conditions in that region. Our exploration licenses in this region conflict with exploration licenses issued by the Sahrawai Arab Democratic Republic."

Suriname

The three sets of rules governing petroleum exploration and production in Suriname are (i) Staatsolie's Concession Agreement (Decree E8-B, Official Gazette 1981 no. 59), (ii) the Mining Decree of 1986 (Official Gazette 1986 no. 28) and (iii) the Petroleum Law 1990 (Official Gazette 1991 no. 7, as amended in 2001).

The Mining Decree granted concession rights for petroleum activities to state enterprises. Staatsolie Maatschappij Suriname N.V. ("Staatsolie") was founded in 1980 as a state enterprise and holds mining rights onshore and offshore in Suriname. The Petroleum Law granted state enterprises with petroleum concession rights the authority, upon the approval of the Minister of Natural Resources, to enter into petroleum contracts with petroleum companies. Therefore, companies who wish to gain rights to explore and produce in Suriname can only do so by entering into a petroleum contract with Staatsolie, subject to approval by the Minister of Natural Resources.

Certain Bermuda Law Considerations

As a Bermuda exempted company, we are subject to regulation in Bermuda. Among other things, we must comply with the provisions of the Bermuda Companies Act regulating the payment of dividends and making of distributions from contributed surplus.

We have been designated by the Bermuda Monetary Authority as a non-resident for Bermuda exchange control purposes. This designation allows us to engage in transactions in currencies other than the Bermuda dollar, and there are no restrictions on our ability to transfer funds (other than funds denominated in Bermuda dollars) in and out of Bermuda or to pay dividends to United States residents who are holders of our common shares.

Under Bermuda law, "exempted" companies are companies formed for the purpose of conducting business outside Bermuda from a principal place of business in Bermuda. As an exempted company, we may not, without a license or consent granted by the Minister of Finance, participate in certain business transactions, including transactions involving Bermuda landholding rights and the carrying on of business of any kind for which we are not licensed in Bermuda.

Employees

As of December 31, 2011, we had approximately 190 employees. None of these employees is represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Corporate Information

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. Kosmos Energy Holdings was formed as an exempted company limited by guarantee pursuant to the laws of the Cayman Islands on March 5, 2004. Pursuant to the terms of a corporate reorganization that was completed simultaneously with the closing of our IPO, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. and as a result, Kosmos Energy Holdings became a wholly-owned subsidiary of Kosmos Energy Ltd.

We maintain a registered office in Bermuda at Clarendon House, 2 Church Street, Hamilton HM 11, Bermuda. The telephone number of our registered offices is (441) 295-5950. Our U.S. subsidiary maintains its headquarters at 8176 Park Lane, Suite 500, Dallas, Texas 75231 and its telephone number is (214) 445-9600. Our web site is *www.kosmosenergy.com.*

Available Information

Kosmos is listed on the NYSE and is traded under the symbol "KOS". We file or furnish annual, quarterly and current reports, proxy statements and other information with the SEC. The public may read and copy any reports, statements or other information at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information about the operation of the public reference room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website at http://www.sec.gov that contains documents we file electronically with the SEC.

The Company also maintains an internet website under the name *www.kosmosenergy.com.* The information on our website is not incorporated by reference into this annual report on Form 10-K and should not be considered a part of this annual report on Form 10-K. Our website is included as an inactive technical reference only. We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonable practicable after such reports are electronically filed with, or furnished to, the SEC.

Item 1A. Risk Factors

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this report, including the consolidated financial statements and the related notes included in "Item 8. Financial Statements and Supplementary Data." If any of the following risks actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones we face. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us.

Risks Relating to the Oil and Natural Gas Industry and Our Business

We have limited proved reserves and areas that we decide to drill may not yield oil and natural gas in commercial quantities or quality, or at all.

We have limited proved reserves. The majority of our oil and natural gas portfolio consists of discoveries without approved PoDs and with limited well penetrations, as well as identified yet unproven prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. However, the areas we decide to drill may not yield oil or natural gas in commercial quantities or quality, or at all. Most of our current discoveries and prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Accordingly, we do not know if any of our discoveries or prospects will contain oil or natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil or natural gas is found on our discoveries or prospects in commercial quantities, construction costs of gathering lines, subsea infrastructure and floating production systems and transportation costs may prevent such discoveries or prospects from being economically viable, and approval of PoDs by various regulatory authorities, a necessary step in order to designate a discovery as "commercial," may not be forthcoming. Additionally, the analogies drawn by us using available data from other wells, more fully explored discoveries or producing fields may not prove valid with respect to our drilling prospects. We may terminate our drilling program for a discovery or prospect if data, information, studies and previous reports indicate that the possible development of a discovery or prospect is not commercially viable and, therefore, does not merit further investment. If a significant number of our discoveries or prospects do not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

The deepwater offshore Ghana, an area in which we focus a substantial amount of our exploration, appraisal and development efforts, has only recently been considered potentially economically viable for hydrocarbon production due to the costs and difficulties involved in drilling for oil at such depths and the relatively recent discovery of commercial quantities of oil in the region. Likewise, our onshore Cameroon and deepwater offshore Morocco and Suriname prospects have not yet proved to be economically viable production areas, as to date we do not have a commercially viable discovery or production in either of these regions. We have limited proved reserves, and we may not be successful in developing additional commercially viable production from our other discoveries and prospects.

We face substantial uncertainties in estimating the characteristics of our unappraised discoveries and our prospects.

In this report we provide numerical and other measures of the characteristics, including with regard to size and quality, of our discoveries and prospects. These measures may be incorrect, as the accuracy of these measures is a function of available data, geological interpretation and judgment. To date, a limited number of our prospects have been drilled. Any analogies drawn by us from other wells, discoveries or producing fields may not prove to be accurate indicators of the success of developing proved reserves from our discoveries and prospects. Furthermore, we have no way of evaluating the accuracy of the data from analog wells or prospects produced by other parties which we may use.

It is possible that few or none of our wells to be drilled will find accumulations of hydrocarbons in commercial quality or quantity. Any significant variance between actual results and our assumptions could materially affect the quantities of hydrocarbons attributable to any particular prospect.

Drilling wells is speculative, often involving significant costs that may be more than we estimate, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services or unanticipated geologic conditions. Before a well is spud, we incur significant geological and geophysical (seismic) costs, which are incurred whether a well eventually produces commercial quantities of hydrocarbons, or is drilled at all. Drilling may be unsuccessful for many reasons, including geologic conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploratory wells bear a much greater risk of loss than development wells. In the past we have experienced unsuccessful drilling efforts, having drilled dry holes. Furthermore, the successful drilling of a well does not necessarily result in the commercially viable development of a field. A variety of factors, including geologic and market-related, can cause a field to become uneconomic or only marginally economic. Many of our prospects that may be developed require significant additional exploration, appraisal and development, regulatory approval and commitments of resources prior to commercial development. The successful drilling of a single well may not be indicative of the potential for the development of a commercially viable field. In Africa and South America, we face higher above-ground risks necessitating higher expected returns, the requirement for increased capital expenditures due to a general lack of infrastructure and underdeveloped oil and gas industries, and increased transportation expenses due to geographic remoteness, which either require a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. See "—Our operations may be adversely affected by political and economic circumstances in the countries in which we operate." Furthermore, if our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and could be forced to modify our plan of operation.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our license areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, approval by block partners and regulators, seasonal conditions, oil prices, assessment of risks, costs and drilling results. The final determination on whether to drill any of these locations will be dependent upon the factors described elsewhere in this report as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

Under the terms of our various license agreements, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to declare any discoveries and thereby establish development areas may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various petroleum agreements and licenses, our interests in the undeveloped parts of our license areas may lapse. Should the prospects we have identified in this report under the license agreements currently in place yield discoveries, we cannot assure you that we will not face delays in drilling these prospects or otherwise have to relinquish these prospects. The costs to maintain licenses over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. Our actual drilling activities may therefore materially differ from our current expectations, which could adversely affect our business.

Regarding our licenses in Ghana, the WCTP PA extends for a period of 30 years from its effective date (July 2004); however, in July 2011, the WCTP Relinquishment Area was subject to relinquishment. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. In July 2010, we and our WCTP Block partners exercised our right to negotiate a new petroleum contract and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. If we are unsuccessful in negotiating a new petroleum agreement or choose to not match a bona fide third party offer for the WCTP Relinquishment Area, the identified prospects within the WCTP Block will not be able to be drilled by us. Further, if we are able to negotiate a new petroleum agreement or match a bona fide third party offer, we cannot assure you that any such new agreement will either be entered into or be on the same terms as the current WCTP PA.

The DT PA also extends for a period of 30 years from its effective date and contains similar relinquishment provisions to the WCTP PA, but with the end of the seven year exploration phase occurring in January 2013. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum agreement with respect to the DT Relinquishment Area. We exercised such right in June 2011. If we are unable to negotiate a new petroleum agreement or we choose to not match a bona fide third party offer for the DT Relinquishment Area, the identified prospects within the DT PA Block will not be able to be drilled by us. Further, if we are able to negotiate a new petroleum agreement or match a bona fide third party offer, we cannot assure you that any such new agreement will either be entered into or be on the same terms as the current DT PA.

Regarding our license in Cameroon, the exploration period for the Ndian River license will expire on November 20, 2012. Kosmos is required to drill one well before the expiration of this renewal period. Failure to do so may result in our loss of the license. Regarding our recently acquired petroleum contract in Cameroon, the Fako Block, the initial exploration period will expire on January 13, 2014. Under this petroleum contract, we have work commitments to perform exploration activities and other related activities totaling $2.1 million. Failure to do so may result in our loss of the license.

Regarding our licenses in Suriname, under the production sharing contract covering Block 42, effective December 13, 2011, Kosmos is obligated during the initial four year exploration phase to conduct certain studies, reprocess existing 2D seismic; acquire, process and interpret 1,400 kilometers of 2D seismic; and acquire, process and interpret 500 square kilometers of 3D seismic. Under the production sharing contract covering Block 45, effective December 13, 2011, Kosmos is obligated during the initial three year exploration phase to conduct certain studies; reprocess existing 2D seismic;

and acquire, process and interpret 1,000 kilometers of 3D seismic. Failure to complete such requirements may result in our loss of these licenses.

We are currently in the initial exploration phase for our petroleum contracts in Morocco. The Cap Boujdour Offshore Block, Essaouira Offshore Block, and the Foum Assaka Offshore Block expire on March 1, 2013, April 21, 2014, and January 1, 2014, respectively. Under these petroleum contracts, we have work commitments to perform exploration activities and other related activities totaling $12.5 million. Failure to do so may result in our loss of the license.

For each of our license areas, we cannot assure you that any renewals or extensions will be granted or whether any new agreements will be available on commercially reasonable terms, or, in some cases, at all. For additional detail regarding the status of our operations with respect to our various licenses, please see "Item 1. Business—Our Geographic Areas of Operation."

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or unit partners. If any of our partners in the blocks or unit in which we hold interests are unable to fund their share of the exploration and development expenses, we may be liable for such costs. In the past, certain of our WCTP and DT Block partners have not paid their share of block costs in the time frame required by the joint operating agreements for these blocks. This has resulted in such party being in default, which in return requires Kosmos and its non-defaulting block partners to pay their proportionate share of the defaulting party's costs during the default period. Should a default not be cured, Kosmos could be required to pay its share of the defaulting party's costs going forward.

Our principal exposure to credit risk will be through receivables resulting from the sale of our oil, which we plan to market to energy marketing companies and refineries, and to cover our commodity derivatives contracts. The inability or failure of our significant customers or counter-parties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Joint interest receivables arise from our block partners. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result.

The interests in and development of the Jubilee Field are governed by the terms of the UUOA. The parties to the UUOA, the collective interest holders in each of the WCTP and DT Blocks, initially agreed that interests in the Jubilee Unit will be shared equally, with each block deemed to contribute 50% of the area of such unit. The respective interests in the Jubilee Unit were therefore initially determined by the respective interests in such contributed block interests. Pursuant to the terms of the UUOA, the percentage of such contributed interests is subject to a process of redetermination once sufficient development work has been completed in the unit. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest (participating interest in the Jubilee Unit) was increased from 23.50868% (our percentage after Tullow's acquisition of EO Group's interest in July 2011) to 24.07710%. A second redetermination could occur sometime after December 31, 2013, if requested by a party that holds greater than a 10% interest in the unit. We cannot assure you that any redetermination pursuant to the terms of the UUOA will not negatively affect our interests in the Jubilee Unit or that such redetermination will be satisfactorily resolved.

We are not, and may not be in the future, the operator on all of our license areas and do not, and may not in the future, hold all of the working interests in certain of our license areas. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and to an extent, any non-wholly owned, assets.

As we carry out our exploration and development programs, we have arrangements with respect to existing license areas and may have agreements with respect to future license areas that result in a greater proportion of our license areas being operated by others. Currently, we are not the Unit Operator on the Jubilee Field and do not hold operatorship in one of our two blocks offshore Ghana (the DT Block). In addition, the terms of the UUOA governing the unit partners' interests in the Jubilee Field require certain actions be approved by at least 80% of the unit voting interests and the terms of our other current or future license or venture agreements may require at least the majority of working interests to approve certain actions. As a result, we may have limited ability to exercise influence over the operations of the discoveries or prospects operated by our block or unit partners, or which are not wholly owned by us, as the case may be. Dependence on block or unit partners could prevent us from realizing our target returns for those discoveries or prospects. Further, because we do not have majority ownership in all of our properties, we may not be able to control the timing of exploration or development activities or the amount of capital expenditures and, therefore, may not be able to carry out one of our key business strategies of minimizing the cycle time between discovery and initial production. The success and timing of exploration and development activities operated by our block partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other block partners in drilling wells;
- the scheduling, pre-design, planning, design and approvals of activities and processes;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations on some of our license areas may cause a material adverse effect on our financial condition and results of operations.

We have been, until recently, a development stage entity and our future performance is uncertain.

We were a development stage entity until we first generated revenue in early 2011. Development stage entities face substantial businessrisks and may suffer significant losses. Until recently, we have generated substantial net losses and negative cash flows from operating activities since our inception and may continue to incur substantial net losses as we continue our exploration and appraisal program. We face challenges and uncertainties in financial planning as a result of the limited amount of historical data and uncertainties regarding the nature, scope and results of our future activities. As a new public company, we will need to develop additional business relationships, establish additional operating procedures, hire additional staff, and take other measures necessary to conduct our intended business activities. We may not be successful in implementing our business strategies or in completing the development of the facilities necessary to conduct our business as planned. In the event that one or more of our drilling programs is not completed, is delayed or terminated, our operating results will be adversely affected and our operations will differ materially from the activities described in this report.

There are uncertainties surrounding our future business operations which must be navigated, some of which may cause a material adverse effect on our results of operations and financial condition.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is technically complex. It requires interpretations of available technical data and many assumptions, including those relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Item 1. Business —Our Reserves" for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2011.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with the SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months, adjusted for anticipated market premium, without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas assets will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- derivative transactions;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas assets will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this report. If oil prices decline by $1.00 per bbl, then the present value of our net revenues at a 10% discount rate ("PV-10") and the Standardized Measure as of December 31, 2011 would each decrease by approximately $19.7 million. See "Item 1. Business—Our Reserves."

We are dependent on certain members of our management and technical team.

Our performance and success largely depend on the ability, expertise, judgment and discretion of our management and the ability of our technical team to identify, discover, evaluate and develop reserves. The loss or departure of one or more members of our management and technical team could be detrimental to our future success. Additionally, a significant amount of shares in Kosmos held by members of our management and technical team have vested. There can be no assurance that our management and technical team will remain in place. If any of these officers or other key personnel resigns or becomes unable to continue in their present roles and is not adequately replaced, our results of operations and financial condition could be materially adversely effected. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

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

We expect our capital outlays and operating expenditures to be substantial as we expand our operations. Obtaining seismic data, as well as exploration, appraisal, development and production activities entail considerable costs, and we expect that we will need to raise substantial additional capital, through additional debt financing, strategic alliances or future private or public equity offerings.

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

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

We do not currently have any commitments for future external funding beyond the capacity of our commercial debt facility. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional securities to raise funds, at such time the ownership percentage of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm-out interests in our licenses, we would dilute our ownership interest subject to the farm-out and any potential value resulting therefrom, and may lose operating control or influence over such license areas.

Assuming we are able to commence exploration, appraisal, development and production activities or successfully exploit our licenses during the exploratory term, our interests in our licenses (or the development/production area of such licenses as they existed at that time, as applicable) could extend beyond such term for a fixed period or life of production, depending on the jurisdiction. If we are unable to meet our well commitments and/or declare commerciality of the prospective areas of our licenses during this time, we may be subject to significant potential forfeiture of all or part of the relevant license interests. If we are not successful in raising additional capital, we may be unable to continue our exploration and production activities or successfully exploit our license areas, and we may lose the rights to develop these areas. See "—Under the terms of our various license agreements, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to declare any discoveries and thereby establish development areas may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects."

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

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

- changes in supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- global economic conditions;
- political and economic conditions, including embargoes in oil-producing countries or affecting other oil-producing activities, particularly in the Middle East, Africa, Russia and South America;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil inventories and oil refining capacities;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- governmental regulations and taxation policies;
- proximity and capacity of transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price, availability or mandated use of alternative fuels.

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

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas assets, and such decreases could result in reduced availability under our commercial debt facility.

We will review our proved oil and natural gas assets for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of appraisal and development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas assets. A write-down constitutes a non-cash charge to earnings.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. Redeterminations may occur as a result of a variety of factors, including the commodity price assumptions, assumptions regarding future production from our oil and natural gas assets, operating costs and tax burdens or assumptions concerning our future holdings of proved reserves. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We may not be able to commercialize our interests in any natural gas produced from our license areas.

The development of the market for natural gas in our license areas is in its early stages. Currently the infrastructure to transport and process natural gas on commercial terms is limited and the expenses associated with constructing such infrastructure ourselves may not be commercially viable given local prices currently paid for natural gas. Accordingly, there may be limited or no value derived from any natural gas produced from our license areas.

Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets or delay our oil and natural gas production.

Our ability to market our oil and natural gas production will depend substantially on the availability and capacity of processing facilities, oil tankers and other infrastructure, including FPSOs, owned and operated by third parties. Our failure to obtain such facilities on acceptable terms could materially harm our business. We also rely on continuing access to drilling rigs suitable for the environment in which we operate. The delivery of drilling rigs may be delayed or cancelled, and we may not be able to gain continued access to suitable rigs in the future. We may be required to shut in oil wells because of the absence of a market or because access to processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could cause a material adverse effect on our financial condition and results of operations. In addition, the shutting in of wells can lead to mechanical problems upon bringing the production back on line, potentially resulting in decreased production and increased remediation costs.

Additionally, the future exploitation and sale of associated and non-associated natural gas and liquids will be subject to timely commercial processing and marketing of these products, which depends on the contracting, financing, building and operating of infrastructure by third parties. The Government of Ghana has announced it will build a gas pipeline from the Jubilee Field to transport such natural gas to the mainland for processing and sale; however, to date, the planning and execution of such pipeline is in its early stages. Even if such pipeline is constructed, it would only give us access to a limited natural gas market. In addition, in connection with the approval of the Jubilee Phase 1 PoD, we granted the first 200 Bcf of natural gas produced from the Jubilee Field Phase 1 development to

Ghana at no cost. The Jubilee Phase 1 PoD provided an initial period during commencement of production for which natural gas could be flared. Subsequent to such period, the Jubilee Phase 1 PoD provided that a portion of the natural gas would be reinjected and the balance of the natural gas would be transported to shore via the pipeline to be built. While reinjection improves the recoverability of oil from such reservoirs in the short term, in order to maintain maximum oil production levels, eventually we will need to either flare excess natural gas or otherwise remove it from the reservoirs' production system. We have not been issued a permit from the Ghana Environmental Protection Agency ("Ghana EPA") to flare natural gas produced from the Jubilee Field in the long-term. In the absence of construction of a natural gas pipeline or if we do not receive a permit to flare such natural gas for the long-term prior to reaching the Jubilee Field Phase 1's reinjection capacity, the field's oil production capacity may be adversely affected.

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

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

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

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas. Our actual operating costs may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, climate change, health and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities, delays, an inability to complete the development of our discoveries or the abandonment of such discoveries, which could cause a material adverse effect on our financial condition and results of operations.

We are subject to drilling and other operational environmental hazards.

The oil and natural gas business involves a variety of operating risks, including, but not limited to:

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

- uncontrolled flows or leaks of oil, well fluids, natural gas, brine, toxic gas or other pollution;
- gas flaring operations;
- marine hazards with respect to offshore operations;
- formations with abnormal pressures;
- pollution, other environmental risks, and geological problems; and
- weather conditions and natural disasters.

These risks are particularly acute in deepwater drilling and exploration. Any of these events could result in loss of human life, significant damage to property, environmental or natural resource damage, impairment, delay or cessation of our operations, adverse publicity, substantial losses and civil or criminal liability. In accordance with customary industry practice, we expect to maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our financial position and results of operations.

The development schedule of oil and natural gas projects, including the availability and cost of drilling rigs, equipment, supplies, personnel and oilfield services, is subject to delays and cost overruns.

Historically, some oil and natural gas development projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

Our offshore and deepwater operations will involve special risks that could adversely affect our results of operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, sinking, collisions and damage or loss to pipeline, subsea or other facilities or from weather conditions. We could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or license acquisitions, or result in loss of equipment and license interests.

Deepwater exploration generally involves greater operational and financial risks than exploration in shallower waters. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks of which we are currently unaware. If we participate in the development of new subsea infrastructure and use floating production systems to transport oil from producing wells, these operations may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in significant liabilities, cost overruns or delays. Furthermore, deepwater operations generally, and operations in Africa and South America in particular, lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Because of the lack of and the high cost of this infrastructure, further discoveries we may make in Africa and South America may never be economically producible.

We had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements.

All of our proved reserves and our discovered fields are located offshore Ghana. The WCTP PA and the DT PA cover the two blocks that form the basis of our exploration, development and production operations in Ghana. Pursuant to these petroleum agreements, most significant decisions, including our plans for development and annual work programs, must be approved by GNPC and/or Ghana's Ministry of Energy. We have previously had disagreements with the Ministry of Energy and GNPC regarding certain of our rights and responsibilities under these petroleum agreements, the Petroleum Law of 1984 (PNDCL 84) (the "Ghanaian Petroleum Law") and the Internal Revenue Act, 2000 (Act 592) (the "Ghanaian Tax Law"). These included disagreements over sharing information with prospective purchasers of our interests, pledging our interests to finance our development activities, potential liabilities arising from discharges of small quantities of drilling fluids into Ghanaian territorial waters, the failure to approve the proposed sale of our Ghanaian assets and assertions that could be read to give rise to taxes payable under the Ghanaian Tax Law in connection with our IPO. These past disagreements have been resolved. In connection with resolving certain of these disagreements, we entered into a settlement agreement with GNPC and the Government of Ghana in December 2010. As part of such agreement and with respect to one particular issue, we agreed to pay GNPC $8 million upon signing the settlement agreement and $15 million upon the first to occur of certain liquidity events, including the successful completion of our IPO.

We issued a Notice of Dispute to the Ministry of Energy and GNPC regarding our right to force majeure protection from an event of Force Majeure that occurred as we were preparing to drill the Cedrela-1 exploration well on the WCTP Block. We continue to discuss this issue so that we may reach an agreement with the Ministry of Energy and GNPC such that we may drill the Cedrela-1 exploration well in 2012. If this dispute is not resolved in our favor, the Cedrela exploration area will become part of the WCTP Relinquishment Area and will be subject to our right to negotiate a new petroleum agreement with respect to the undeveloped parts of the WCTP Block, unless we and our WCTP Block partners do not wish to match any bona fide third party offer received by GNPC; however, we cannot assure you that any such new petroleum agreement will either be entered into or be on the same terms as the current WCTP PA. We also issued a Notice of Dispute to the Ministry of Energy and GNPC regarding the lack of approval of the Mahogany East PoD. We continue to discuss resolution of the PoD with the Ministry of Energy and GNPC.

There can be no assurance that future disagreements will not arise with any host government and/or national oil companies that may have a material adverse effect on our exploration or development activities, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests.

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

Our current exploration licenses are located in Africa and South America. Some or all of these licenses could be affected should either region experience any of the following factors (among others):

- severe weather or natural disasters or other acts of God;
- delays or decreases in production, the availability of equipment, facilities, personnel or services;
- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- military conflicts or civil unrest.

For example, oil and natural gas operations in our license areas may be subject to higher political and security risks than those operations under the sovereignty of the United States. We plan to maintain insurance coverage for only a portion of the risks we face from doing business in these regions. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss.

Further, as many of our licenses are concentrated in the same geographic area, a number of our licenses could experience the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of licenses.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Oil and natural gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes in energy policies or the personnel administering them), changes in laws and policies governing operations of foreign -based companies, expropriation of property, cancellation or modification of contract rights, revocation of consents or approvals, obtaining various approvals from regulators, foreign exchange restrictions, currency fluctuations, royalty increases and other risks arising out of foreign governmental sovereignty, as well as risks of loss due to civil strife, acts of war, guerrilla activities, terrorism, acts of sabotage, territorial disputes and insurrection. In addition, we are subject both to uncertainties in the application of the tax laws in the countries in which we operate and to possible changes in such tax laws (or the application thereof), each of which could result in an increase in our tax liabilities. These risks may be higher in the developing countries in which we conduct our activities.

Our operations in these areas increase our exposure to risks of war, local economic conditions, political disruption, civil disturbance, expropriation, piracy, tribal conflicts and governmental policies that may:

- disrupt our operations;
- require us to incur greater costs for security;
- restrict the movement of funds or limit repatriation of profits;
- lead to U.S. government or international sanctions; or
- limit access to markets for periods of time.

Some countries in the geographic areas where we operate have experienced political instability in the past or are currently experiencing instability. Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our offshore exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our results of operations and financial condition. Furthermore, in the event of a dispute arising from non-U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the United States or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the United States, which could adversely affect the outcome of such dispute.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including Ghana, Cameroon, Morocco, Suriname, the United States, the United Kingdom, Bermuda and the Cayman Islands and other jurisdictions in which we do business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof, could materially and adversely affect our financial position, results of operations and cash flows.

A portion of our asset portfolio is in Western Sahara, and we could be adversely affected by the political, economic and military conditions in that region. Our exploration licenses in this region conflict with exploration licenses issued by the Sahrawai Arab Democratic Republic.

Morocco claims the territory of Western Sahara, where our Cap Boujdour Offshore Block is geographically located, as part of the Kingdom of Morocco, and it has *de facto* administrative control of approximately 80% of Western Sahara. However, Western Sahara is on the United Nations (the "UN") list of Non-Self-Governing territories, and the territory's sovereignty has been in dispute since 1975. The Polisario Front, representing the SADR, has a conflicting claim of sovereignty over Western Sahara. No countries have formally recognized Morocco's claim to Western Sahara, although some countries implicitly support Morocco's position. Other countries have formally recognized the SADR, but the UN has not. A UN-administered cease-fire has been in place since 1991, and while there have been intermittent UN-sponsored talks, between Morocco and SADR (represented by the Polisario), the dispute remains stalemated. It is uncertain when and how Western Sahara's sovereignty issues will be resolved.

We own a 75% working interest in the Cap Boujdour Offshore Block located geographically offshore Western Sahara. Our licenses were granted by the government of Morocco; however, the SADR has issued its own offshore exploration licenses which, in some areas, conflict with our licenses. As a result of SADR's conflicting claim of rights to oil and natural gas licenses granted by Morocco, and the SADR's claims that Morocco's exploitation of Western Sahara's natural resources violates international law, our interests could decrease in value or be lost. Any political instability, terrorism, changes in government, or escalation in hostilities involving the SADR, Morocco or neighboring states could adversely affect our operations and assets. In addition, Morocco has recently experienced political and social disturbances that could affect its legal and administrative institutions. A change in U.S. foreign policy or the policies of other countries regarding Western Sahara could also adversely affect our operations and assets. We are not insured against political or terrorism risks because management deems the premium costs of such insurance to be currently prohibitively expensive relative to the limited coverage provided thereby.

Furthermore, various activist groups have mounted public relations campaigns to force companies to cease and divest operations in Western Sahara, and we could come under similar public pressure. Some investors have refused to invest in companies with operations in Western Sahara, and we could be subject to similar pressure. Any of these factors could have a material adverse effect on our results of operations and financial condition.

Maritime boundary demarcation between Côte D'Ivoire and Ghana may affect a portion of our license areas.

In early 2010, Ghana's western neighbor, the Republic of Côte d'Ivoire, petitioned the United Nations to demarcate the Ivorian territorial maritime boundary with Ghana. In response to the petition, Ghana established a Boundary Commission to undertake negotiations in order to determine Ghana's land and maritime boundaries. Ghana has opted out of compulsory dispute settlement under the United Nations Convention on the Law of the Sea. As such we expect that this matter will likely be resolved via bilateral discussions between the Governments. We understand that such discussions are continuing, although the status and results of these discussions have not been announced and the issue remains unresolved at present. The Ghanaian-Ivorian maritime boundary forms the western boundary of the DT Block offshore Ghana. In September, 2011, the Ivorian Government issued a map reflecting potential petroleum license areas that overlap with the DT Block, although no conflicting licenses have been awarded. Uncertainty remains with regard to the outcome of the boundary demarcation between Ghana and Côte d'Ivoire and we do not know if the maritime boundary will change, therefore affecting our rights to explore and develop our discoveries or prospects within such areas.

The oil and gas industry, including the acquisition of exploratory licenses in Africa and South America, is intensely competitive and many of our competitors possess and employ substantially greater resources than us.

The international oil and gas industry, including Africa and South America, is highly competitive in all aspects, including the exploration for, and the development of, new license areas. We operate in a highly competitive environment for acquiring exploratory licenses and hiring and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than us, which can be particularly important in the areas in which we operate. These companies may be better able to withstand the financial pressures of unsuccessful drill attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which could adversely affect our competitive position. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable licenses and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. As a result of these and other factors, we may not be able to compete successfully in an intensely competitive industry, which could cause a material adverse effect on our results of operations and financial condition.

Participants in the oil and gas industry are subject to numerous laws that can affect the cost, manner or feasibility of doing business.

Exploration and production activities in the oil and gas industry are subject to local laws and regulations. We may be required to make large expenditures to comply with governmental laws and regulations, particularly in respect of the following matters:

- licenses for drilling operations;
- tax increases, including retroactive claims;
- unitization of oil accumulations;
- local content requirements (including the mandatory use of local partners and vendors); and
- environmental requirements and obligations, including remediation or investigation activities.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change, or their interpretations could change, in ways that could substantially increase our costs. These risks may be higher in the developing countries in which we conduct our operations, where there could be a lack of clarity or lack of consistency in the application of these laws and regulations. Any resulting liabilities, penalties, suspensions or terminations could have a material adverse effect on our financial condition and results of operations.

For example, Ghana's Parliament has recently enacted the Petroleum Revenue Management Act and is considering the enactment of a new Petroleum Exploration and Production Act. There can be no assurance that these laws will not seek to retroactively, either on their face or as interpreted, modify the terms of the agreements governing our license interests in Ghana, including the WCTP and DT PAs and the UUOA, require governmental approval for transactions that effect a direct or indirect change of control of our license interests or otherwise affect our current and future operations in Ghana. Any such changes may have a material adverse affect on our business. We also cannot assure you that government approval will not be needed for direct or indirect transfers of our petroleum agreements or interests thereunder based on existing legislation. See "Item 1. Business—Other Regulation of the Oil and Gas Industry—Ghana."

Furthermore, the Macondo incident in the Gulf of Mexico may have increased certain of the risks faced by those drilling for oil in deepwater regions, including, without limitation, the following:

- increased industry standards, governmental regulation and enforcement of our and our industry's operations in a number of areas, including health and safety, financial responsibility, environmental, licensing, taxation, equipment specifications and training requirements;
- increased difficulty or delays in obtaining rights to drill wells in deepwater regions;
- higher operating costs;
- higher insurance costs and increased potential liability thresholds under environmental laws;
- decreased access to appropriate equipment, personnel and infrastructure in a timely manner;
- higher capital costs as a result of any increase to the risks we or our industry face; and
- less favorable investor perception of the risk-adjusted benefits of deepwater offshore drilling.

The occurrence of any of these factors, or the continuation thereof, could have a material adverse effect on our business, financial position or future results of operations.

We and our operations are subject to numerous environmental, health and safety regulations which may result in material liabilities and costs.

We and our operations are subject to various international, foreign, federal, state and local environmental, health and safety laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use and transportation of regulated materials and the health and safety of our employees. We are required to obtain environmental permits from governmental authorities for our operations, including drilling permits for our wells. We have not been or may not be at all times in complete compliance with these permits and the environmental laws and regulations to which we are subject, and there is a risk that these laws and regulations could change in the future or become more stringent. If we violate or fail to comply with these laws, regulations or permits, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain permits in a timely manner or at all (due to opposition from partners, community or environmental interest groups, governmental delays or any other reasons), or if we face additional requirements imposed as a result of changes in or enactment of laws or regulations, such failure to obtain permits or such changes in or enactment of laws could impede or affect our operations, which could have a material adverse effect on our results of operations and financial condition.

We, as an interest owner or as the designated operator of certain of our current and future discoveries and prospects, could be held liable for some or all environmental, health and safety costs and liabilities arising out of our actions and omissions as well as those of our block partners, third-party contractors or other operators. To the extent we do not address these costs and liabilities or if we do not otherwise satisfy our obligations, our operations could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform services related to our operations. There is a risk that we may contract with third parties with unsatisfactory environmental, health and safety records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions. Accordingly, we could be held liable for all costs and liabilities arising out of the acts or omissions of our contractors, which could have a material adverse effect on our results of operations and financial condition.

We are not fully insured against all risks and our insurance may not cover any or all environmental claims that might arise from our operations or at any of our license areas. If a significant accident or other event occurs and is not covered by insurance, such accident or event could have a material adverse effect on our results of operations and financial condition.

Releases of regulated substances may occur and can be significant. Under certain environmental laws, we could be held responsible for all of the costs relating to any contamination at our facilities and at any third party waste disposal sites used by us or on our behalf. In addition, offshore oil and natural gas exploration and production involves various hazards, including human exposure to regulated substances, which include naturally occurring radioactive and other materials. As such, we could be held liable for any and all consequences arising out of human exposure to such substances or for other damage resulting from the release of hazardous substances to the environment, property or to natural resources, or affecting endangered species.

In addition, we expect continued and increasing attention to climate change issues. Various countries and regions have agreed to regulate emissions of GHGs, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). The regulation of GHGs and the physical impacts of climate change in the areas in which we, our customers and the end-users of our products operate could adversely impact our operations and the demand for our products.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future climate change, environmental, health and safety laws, the actions or omissions of our block partners and third party contractors and our liabilities arising from releases of, or exposure to, regulated substances may adversely affect our results of operations and financial condition. See "Item 1. Business—Environmental Matters."

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act and other anti-corruption laws, and any determination that we violated the U.S. Foreign Corrupt Practices Act or other such laws could have a material adverse effect on our business.

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign government officials and political parties for the purpose of obtaining or retaining business or otherwise securing an improper business advantage. In addition, the United Kingdom has enacted the Bribery Act of 2011, and we may be subject to that legislation under certain circumstances. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials. We face the risk of unauthorized payments or offers of payments by one of our employees or consultants. Our existing safeguards and any future improvements may prove to be less than effective in preventing such unauthorized payments, and our employees and consultants may engage in conduct for which we might be held responsible. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the U.S. government may seek to hold us liable for successor liability FCPA violations committed by companies in which we invest or that we acquire.

We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage.

We intend to maintain insurance against certain risks in the operation of the business we plan to develop and in amounts in which we believe to be reasonable. Such insurance, however, may contain exclusions and limitations on coverage. For example, we are not insured against political or terrorism risks. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have and may in the future enter into derivative arrangements for a portion of our oil and natural gas production, including, but not limited to, puts, collars and fixed-price swaps. In addition, we currently, and may in the future, hold swaps designed to hedge our interest rate risk. We do not currently designate any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements may limit the benefit we could receive from increases in the prices for oil and natural gas or beneficial interest rate fluctuations and may expose us to cash margin requirements.

Our commercial debt facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our commercial debt facility includes certain covenants that, among other things, restrict:

- our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the commercial debt facility and certain permitted liens;
- mergers, consolidations and sales of all or a substantial part of our business or licenses;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets (other than production sold in the ordinary course of business); and
- our capital expenditures that we can fund with our commercial debt facility.

Our commercial debt facility requires us to maintain certain financial ratios, such as debt service coverage ratios. All of these restrictive covenants may limit our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility may be impacted by changes in economic or business conditions, our results of operations or events beyond our control. The breach of any of these covenants could result in a default under our commercial debt facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our commercial debt facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders, successors or assignees could proceed against their collateral. If the indebtedness under our commercial debt facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

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

In March 2011 we entered into a $2.0 billion commercial debt facility (the "Facility"), which may be increased to $3.0 billion upon our obtaining additional commitments. At December 31, 2011, we had $1.1 billion outstanding and $890 million of committed undrawn capacity under such facility, of which $153 million was available. In the future, we may incur significant indebtedness in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion or all of our cash flows, when generated, could be used to service our indebtedness;
- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional hedging instruments may be required as a result of our indebtedness;
- a high level of indebtedness may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness. Factors that will affect our ability to raise cash through an offering of our equity securities or a refinancing of our indebtedness include financial market conditions, the value of our assets and our performance at the time we need capital.

Our operations may be adversely affected by the European debt crisis.

During 2011, the long term structural deficits in numerous European nations coupled with the deterioration of the economic outlook led the weaker nations to a liquidity and solvency crisis. Eurozone leaders have made numerous attempts to solve this debt crisis; but, to date a sustainable long term solution has not been implemented and much uncertainty remains. The crisis has had a negative impact on major European banks which historically were significant providers of credit to the energy sector, globally and in the US.

As of December 31, 2011, our Facility includes $2.0 billion in aggregate total commitments of which $153 million was available; approximately 60%, or $91.0 million, of the undrawn availability under the Facility as of December 31, 2011 was with European financial institutions. If any of the financial institutions within our Facility are unable to perform on their commitments, our liquidity could be impacted which could have a significant negative impact on our earnings, cash flows and financial position.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of prospects and licenses, reserves and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of these assets requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject assets that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We may not be entitled to contractual indemnification for environmental liabilities and could acquire assets on an "as is" basis. Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be adversely affected.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of environmental or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

We have a material weakness in our internal control over financial reporting. If we fail to establish and maintain proper and effective internal controls, our ability to produce accurate financial statements could be impaired, which could adversely affect our operating results, and investor, supplier and customer confidence in our reported financial information.

As described in "Item 9A. Controls and Procedures," during the quarter ended December 31, 2011, management determined that the Company had a material weaknesses in its system of internal control over financial reporting. A material weakness is a deficiency, or combination of deficiencies in internal controls over financial reporting that results in a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. 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. While the Company has taken steps to remediate this material weakness, at December 31, 2011, the Company had not yet completed its assessment as to whether the material weakness had been fully remediated. Until it is fully remediated, this material weakness could lead to errors in our reported financial results and could have a material adverse effect on our operations, investor, supplier and customer confidence in our reported financial information and the trading price of our common shares.

Because we are a relatively small company, the requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we must comply with additional laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Lastly, we are evaluating the potential listing of our common shares on the Ghana Stock Exchange ("GSE"), although there can be no assurance that this listing will be completed in a timely manner, or at all. Complying with the regulations and requirements of the GSE may heighten the risks listed above.

Our bye-laws contain a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or future prospects.

Our bye-laws provide that, to the fullest extent permitted by applicable law, we renounce any right, interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time be presented to certain of our affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any statutory, fiduciary, contractual or other duty, as a director or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director, such person fails to present any business opportunity that is expressly offered to such person solely in his or her capacity as our director.

As a result, our directors and certain of our affiliates and their respective affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they or their affiliates have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing of our interest and expectancy in any business opportunity that may be from time to time presented to our directors and certain of our affiliates and their respective affiliates could adversely impact our business or future prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

We receive certain beneficial tax treatment as a result of being an exempted company incorporated pursuant to the laws of Bermuda. Changes in that treatment could have a material adverse effect on our net income, our cash flow and our financial condition.

We are an exempted company incorporated pursuant to the laws of Bermuda and operate through subsidiaries in a number of countries throughout the world. Consequently, we are subject to changes in tax laws, treaties or regulations or the interpretation or enforcement thereof in the United States, Bermuda, Ghana, and other jurisdictions in which we or any of our subsidiaries operate or are resident. Recent legislation has been introduced in the Congress of the United States that is intended to reform the U.S. tax laws as they apply to certain non-U.S. entities and operations, including legislation that would treat a foreign corporation as a U.S. corporation for U.S. federal income tax purposes if substantially all of its senior management is located in the United States. If this or other legislation is passed that ultimately changes our U.S. tax position, it could have a material adverse effect on our net income, our cash flow and our financial condition.

We may become subject to taxes in Bermuda after March 31, 2035, which may have a material adverse effect on our results of operations.

The Bermuda Minister of Finance, under the Exempted Undertakings Tax Protection Act 1966 of Bermuda, as amended, has given us an assurance that if any legislation is enacted in Bermuda that would impose tax computed on profits or income, or computed on any capital asset, gain or appreciation, or any tax in the nature of estate duty or inheritance tax, then the imposition of any such tax will not be applicable to us or any of our operations, shares, debentures or other obligations until March 31, 2035, except insofar as such tax applies to persons ordinarily resident in Bermuda or to any taxes payable by us in respect of real property owned or leased by us in Bermuda.

The impact of Bermuda's letter of commitment to the Organization for Economic Cooperation and Development to eliminate harmful tax practices is uncertain and could adversely affect our tax status in Bermuda.

The Organization for Economic Cooperation and Development ("OECD") has published reports and launched a global initiative among member and non-member countries on measures to limit harmful tax competition. These measures are largely directed at counteracting the effects of tax havens and preferential tax regimes in countries around the world. According to the OECD, Bermuda is a jurisdiction that has substantially implemented the internationally agreed tax standard and as such is listed on the OECD "white" list. However, we are not able to predict whether any changes will be made to this classification or whether such changes will subject us to additional taxes.

The adoption of financial reform legislation by the United States Congress in 2010 could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price and other risks associated with our business.

We use derivative instruments to manage our commodity price risk. The United States Congress adopted comprehensive financial reform legislation in 2010 that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as ours, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law by the President on July 21, 2010, and its provisions generally are effective 360 days from the date of enactment, or July 16, 2011. Provisions that require rulemaking by the Commodities Futures Trading Commission (the "CFTC") and the SEC will not take effect until at least 60 days after publication of the related final rule. The CFTC and the SEC have not completed all of the rulemaking the Dodd-Frank Act directs them to carry out. The regulators have granted temporary relief from the general effective date for various requirements of the Dodd-Frank Act, and also have indicated they may phase in implementation of various requirements of the new rules. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC adopted these proposed regulations with modifications on October 18, 2011, but it is not possible at this time to predict when these regulations will take effect. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Lastly, the Dodd-Frank Act requires the SEC to promulgate rules requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to include in their annual reports filed with the SEC disclosure about all payments (including taxes, royalties, fees and other amounts) made by the issuer or an entity controlled by the issuer to the United States or to any non-U.S. government for the purpose of commercial development of oil, natural gas or minerals. As these rules are not yet effective, we are unable to predict what form the final rules may take and whether we will be able to comply with them without adversely impacting our business, or at all. Any of these consequences could have a material adverse effect on our business, financial condition or results of operations.

We may be or become a "passive foreign investment company" for U.S. federal income tax purposes, which could create adverse tax consequences for U.S. investors.

U.S. investors that hold stock in a "passive foreign investment company" ("PFIC") are subject to special rules that can create adverse U.S. federal income tax consequences, including imputed interest charges and recharacterization of certain gains and distributions. Based on management estimates and projections of future revenue, we do not believe that we will be a PFIC for the current taxable year and we do not expect to become one in the foreseeable future. Because PFIC status is a factual determination that is made annually and thus is subject to change, there can be no assurance that we will not be a PFIC for any taxable year.

We could incur a liability in connection with securities litigation.

On January 10, 2012, a lawsuit was filed in the 68th Judicial District Court of Dallas County, Texas, against Kosmos Energy Ltd., all of our directors, certain officers of the Company, Warburg Pincus LLC, Blackstone Capital Partners and the underwriters of our IPO, alleging violations of the federal securities laws. Specifically, the plaintiff alleged, among other things, that the defendants made materially false statements and omissions in the documents related to the IPO concerning anticipated gross oil production from the Jubilee Field and that the defendants failed to disclose that several wells were not producing as expected due to design defects that will purportedly cost hundreds of millions of dollars to remediate and will purportedly keep such wells from producing as expected for several years. The plaintiff seeks to certify the lawsuit as a class action lawsuit.

We intend to defend vigorously against the lawsuit and do not believe it will have a material adverse effect on our business. However, if we are unsuccessful in this litigation and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

From time to time, we also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the occurrence or outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

Risks Relating to Our Common Shares

Our share price may be volatile, and purchasers of our common shares could incur substantial losses.

Our share price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. The market price for our common shares may be influenced by many factors, including, but not limited to:

- the price of oil and natural gas;

- the success of our exploration and development operations, and the marketing of any oil and natural gas we produce;
- regulatory developments in Bermuda, the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- analysts' reports or recommendations;
- the failure of securities analysts to cover our common shares or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common shares;
- the issuance of any additional securities of ours;
- investor perception of our company and of the industry in which we compete; and
- general economic, political and market conditions.

A substantial portion of our total issued and outstanding common shares may be sold into the market at any time. This could cause the market price of our common shares to drop significantly, even if our business is doing well.

All of the shares sold in our IPO are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all of the remaining common shares are restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rule 144 or Rule 701 under the Securities Act. All of our restricted shares became eligible for sale in the public market beginning in late 2011, subject in certain circumstances to the volume, manner of sale and other limitations under Rule 144. Additionally, we have registered all our common shares that we may issue under our employee benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these share awards have transfer restrictions attached to them. Sales of a substantial number of our common shares, or the perception in the market that the holders of a large number of shares intend to sell common shares, could reduce the market price of our common shares.

The concentration of our share capital ownership among our largest shareholders, and their affiliates, will limit your ability to influence corporate matters.

Our two largest shareholders collectively own approximately 72% of our issued and outstanding common shares. Consequently, these shareholders have significant influence over all matters that require approval by our shareholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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

We may issue additional common shares, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We continue to actively seek to expand our business through complementary or strategic acquisitions of assets, and we may issue additional common shares in connection with those acquisitions. We also issue restricted shares to our executive officers, employees and independent directors as part of their compensation. If we issue additional common shares in the future, it may have a dilutive effect on our current outstanding shareholders.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for and rely on exemptions from certain corporate governance requirements.

Funds affiliated with Warburg Pincus LLC and The Blackstone Group L.P., respectively, continue to control a majority of the voting power of our issued and outstanding common shares, and we are a "controlled company" within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual self assessment evaluation of the nominating and corporate governance and compensation committees.

We have elected to be treated as a controlled company and utilize these exemptions, including the exemption for a board of directors composed of a majority of independent directors. In addition, although we have adopted charters for our audit, nominating and corporate governance and compensation committees and intend to conduct annual self assessment for these committees, currently, none of these committees are composed entirely of independent directors. We have elected to rely on the phase-in rules of the SEC and the NYSE with respect to the independence of our audit committee. These rules permit us to have an audit committee that has one member that is independent upon the effectiveness of the registration statement for our IPO, a majority of members that are independent within 90 days thereafter and all members that are independent within one year thereafter. Accordingly, you may not have the same protections afforded to shareholders of companies that are subject to all of the NYSE corporate governance requirements.

We do not intend to pay dividends on our common shares and, consequently, your only opportunity to achieve a return on your investment is if the price of our shares appreciates.

We do not plan to declare dividends on shares of our common shares in the foreseeable future. Additionally, certain of our subsidiaries are currently restricted in their ability to pay dividends to us pursuant to the terms of our commercial debt facility unless they meet certain conditions, financial and otherwise. Consequently, investors must rely on sales of their common shares after price appreciation, which may never occur, as the only way to realize a return on their investment.

We are a Bermuda company and a significant portion of our assets are located outside the United States. As a result, it may be difficult for shareholders to enforce civil liability provisions of the federal or state securities laws of the United States.

We are a Bermuda exempted company. As a result, the rights of holders of our common shares will be governed by Bermuda law and our memorandum of association and bye-laws. The rights of shareholders under Bermuda law may differ from the rights of shareholders of companies incorporated in other jurisdictions. One of our directors is not a resident of the United States, and a substantial portion of our assets are located outside the United States. As a result, it may be difficult for investors to effect service of process on that person in the United States or to enforce in the United States judgments obtained in U.S. courts against us or that person based on the civil liability provisions of the U.S. securities laws. It is doubtful whether courts in Bermuda will enforce judgments obtained in other jurisdictions, including the United States, against us or our directors or officers under the securities laws of those jurisdictions or entertain actions in Bermuda against us or our directors or officers under the securities laws of other jurisdictions.

Bermuda law differs from the laws in effect in the United States and might afford less protection to shareholders.

Our shareholders could have more difficulty protecting their interests than would shareholders of a corporation incorporated in a jurisdiction of the United States. As a Bermuda company, we are governed by the Companies Act 1981 of Bermuda (the "Bermuda Companies Act"). The Bermuda Companies Act differs in some material respects from laws generally applicable to U.S. corporations and shareholders, including the provisions relating to interested directors, mergers and acquisitions, takeovers, shareholder lawsuits and indemnification of directors. Set forth below is a summary of these provisions, as well as modifications adopted pursuant to our bye-laws, which differ in certain respects from provisions of Delaware corporate law. Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and our shareholders.

Interested Directors. Under Bermuda law and our bye-laws, as long as a director discloses a direct or indirect interest in any contract or arrangement with us as required by law, such director is entitled to vote in respect of any such contract or arrangement in which he or she is interested, unless disqualified from doing so by the chairman of the meeting, and such a contract or arrangement will not be voidable solely as a result of the interested director's participation in its approval. In addition, the director will not be liable to us for any profit realized from the transaction. In contrast, under Delaware law, such a contract or arrangement is voidable unless it is approved by a majority of disinterested directors or by a vote of shareholders, in each case if the material facts as to the interested director's relationship or interests are disclosed or are known to the disinterested directors or shareholders, or such contract or arrangement is fair to the corporation as of the time it is approved or ratified. Additionally, such interested director could be held liable for a transaction in which such director derived an improper personal benefit.

Mergers and Similar Arrangements. The amalgamation of a Bermuda company with another company or corporation (other than certain affiliated companies) requires the amalgamation agreement to be approved by the company's board of directors and by its shareholders. Unless the company's bye-laws provide otherwise, the approval of 75% of the shareholders voting at such meeting is required to approve the amalgamation agreement, and the quorum for such meeting must be two persons holding or representing more than one-third of the issued shares of the company. Our bye-laws provide that an amalgamation (other than with a wholly owned subsidiary, per the Bermuda Companies Act) that has been approved by the board must only be approved by shareholders owning a majority of the issued and outstanding shares entitled to vote. Under Bermuda law, in the event of an amalgamation of a Bermuda company with another company or corporation, a shareholder of the Bermuda company who is not satisfied that fair value has been offered for such shareholder's shares may, within one month of notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the fair value of those shares. Under Delaware law, with certain exceptions, a merger, consolidation or sale of all or substantially all the assets of a corporation must be approved by the board of directors and a majority of the issued and outstanding shares entitled to vote thereon. Under Delaware law, a shareholder of a corporation participating in certain major corporate transactions may, under certain circumstances, be entitled to appraisal rights pursuant to which such shareholder may receive cash in the amount of the fair value of the shares held by such shareholder (as determined by a court) in lieu of the consideration such shareholder would otherwise receive in the transaction.

Shareholders' Suit. Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company's memorandum of association or bye-laws. Furthermore, consideration would be given by a Bermuda court to acts that are alleged to constitute a fraud against the minority shareholders or where an act requires the approval of a greater percentage of the company's shareholders than that which actually approved it.

When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply to the Supreme Court of Bermuda, which may make such order as it sees fit, including an order regulating the conduct of the company's affairs in the future or ordering the purchase of the shares of any shareholders by other shareholders or by the company.

Our bye-laws contain a provision by virtue of which we and our shareholders waive any claim or right of action that they have, both individually and on our behalf, against any director or officer in relation to any action or failure to take action by such director or officer, except in respect of any fraud or dishonesty of such director or officer. Class actions and derivative actions generally are available to shareholders under Delaware law for, among other things, breach of fiduciary duty, corporate waste and actions not taken in accordance with applicable law. In such actions, the court has discretion to permit the winning party to recover attorneys' fees incurred in connection with such action.

Indemnification of Directors. We may indemnify our directors and officers in their capacity as directors or officers for any loss arising or liability attaching to them by virtue of any rule of law in respect of any negligence, default, breach of duty or breach of trust of which a director or officer may be guilty in relation to the company other than in respect of his own fraud or dishonesty. Under Delaware law, a corporation may indemnify a director or officer of the corporation against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred in defense of an action, suit or proceeding by reason of such position if such director or officer acted in good faith and in a manner he or she reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, such director or officer had no reasonable cause to believe his or her conduct was unlawful. In addition, we have entered into customary indemnification agreements with our directors.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

See "Item 1. Business." We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Note 18 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

On January 10, 2012, a lawsuit was filed in the 68th Judicial District Court of Dallas County, Texas, against Kosmos Energy Ltd., all of our directors, certain officers of the Company, Warburg

Pincus LLC, Blackstone Capital Partners and the underwriters of our IPO, alleging violations of the federal securities laws. Specifically, the plaintiff alleged, among other things, that the defendants made materially false statements and omissions in the documents related to the IPO concerning anticipated gross oil production from the Jubilee Field and that the defendants failed to disclose that several wells were not producing as expected due to design defects that will purportedly cost hundreds of millions of dollars to remediate and will purportedly keep such wells from producing as expected for several years. The plaintiff seeks to certify the lawsuit as a class action lawsuit.

We believe that these claims are without merit and intend to defend this lawsuit vigorously. We are cooperating with our directors and officers liability insurance carrier regarding the vigorous defense of the lawsuit. We currently believe that the potential amount of losses resulting from this lawsuit in the future, if any, will not exceed the policy limits of our directors' and officers' insurance.

From time to time, we also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the occurrence or outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

Item 4. Mine Safety Disclosure

Not applicable.

PART II

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

Common Shares Trading Summary

Kosmos' common shares are traded on the NYSE under the symbol "KOS." The following table shows the quarterly high and low sale prices of our common shares as reported on the NYSE since our common shares commenced trading on the NYSE on May 11, 2011 in connection with our IPO.

	Year Ended December 31, 2011	
	High	Low
First Quarter	$ N/A	$ N/A
Second Quarter	19.24	16.63
Third Quarter	17.32	11.51
Fourth Quarter	16.19	10.53

As of February 17, 2012, based on information from the Company's transfer agent, Computershare Trust Company, N.A., the number of holders of record of Kosmos' common shares was 197. On February 17, 2012, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was $14.48 per share.

We have never paid any dividends on our common shares. At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. Additionally, we are subject to Bermuda legal constraints that may affect our ability to pay dividends on our common shares and make other payments. Under the Bermuda Companies Act, we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than the aggregate of our liabilities, issued share capital and share premium accounts. Certain of our subsidiaries are also currently restricted in their ability to pay dividends to us pursuant to the terms of our commercial debt facility unless we meet certain conditions, financial and otherwise. Any decision to pay dividends in the future is at the discretion of our board of directors and depends on our financial condition, results of operations, capital requirements and other factors that our board of directors deems relevant and currently do not anticipate paying any dividends in the foreseeable future.

Unregistered Sales of Equity Securities and Use of Proceeds

Our IPO of common shares was effected through a Registration Statement on Form S-1 (File No. 333-171700) that was declared effective by the SEC on May 10, 2011, which (combined with the Registration Statement on Form S-1 (File No. 333-174116)) registered an aggregateof 38.0 million of our common shares at a public offering price of $18.00 per share. Our IPO resulted in gross proceeds of approximately $621.3 million. Our net proceeds from the sale of an aggregate of 34.5 million common shares after underwriting discounts and commissions and offering expenses of $40.9 million were approximately $580.4 million.

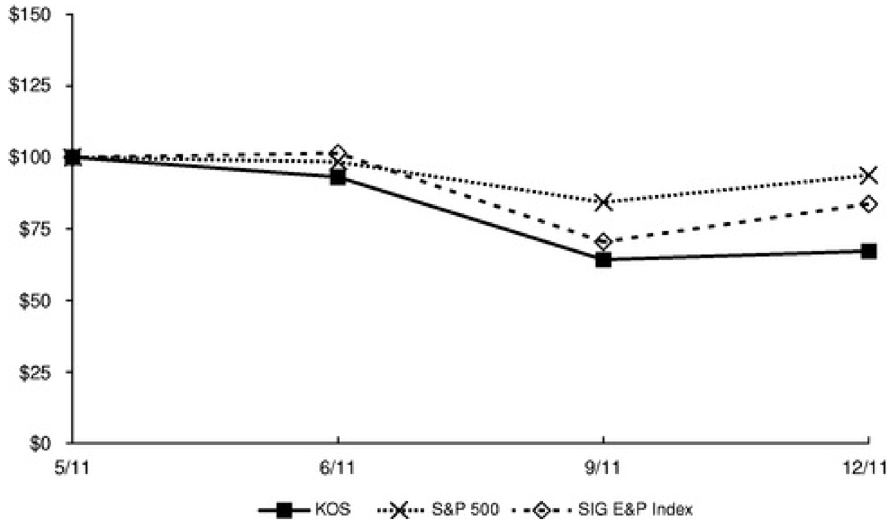
There has been no material change in our planned use of proceeds from the IPO from that described in our final prospectus dated May 10, 2011 and filed with the SEC pursuant to Rule 424(b).

During 2011, we used net proceeds to repay indebtedness under our Facility, to pay funds to GNPC as part of our settlement agreement with GNPC and the Government of Ghana and for general corporate purposes. Pending use of the remaining net proceeds, we have invested these net proceeds in institutionally-managed accounts that consists of highly rated investment funds.

Share Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The following graph illustrates changes over the period from May 11, 2011 (date our common shares commenced trading on the NYSE) through December 31, 2011, in cumulativetotal stockholder return on our common shares as measured against the cumulative total return of the S&P 500 Index and the SIG Oil Exploration & Production Index. The graph tracks the performance of a $100 investment in our common shares and in each index (with the reinvestment of all dividends).



	May 11, 2011	December 31, 2011
Kosmos Energy Ltd.	$ 100.00	$ 67.21
S&P 500	100.00	93.71
SIG Oil Exploration & Production Index	100.00	83.69

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Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2011, should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

Consolidated Statements of Operations Information:

	Year Ended December 31,				
	2011(1)	2010	2009	2008	2007
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$ 666,912	$ —	$ —	$ —	$ —
Interest income	9,093	4,231	985	1,637	1,568
Other income	775	5,109	9,210	5,956	2
Total revenues and other income	676,780	9,340	10,195	7,593	1,570
Costs and expenses:					
Oil and gas production	83,551	—	—	—	—
Exploration expenses, including dry holes	126,409	73,126	22,127	15,373	39,950
General and administrative	113,579	98,967	55,619	40,015	18,556
Depletion, depreciation and amortization	140,469	2,423	1,911	719	477
Amortization—deferred financing costs	16,193	28,827	2,492	—	—
Interest expense	65,749	59,582	6,774	1	8
Derivatives, net	11,777	28,319	—	—	—
Equity in losses of joint venture	—	—	—	—	2,632
Loss on extinguishment of debt	59,643	—	—	—	—
Doubtful accounts expense	(39,782)	39,782	—	—	—
Other expenses, net	149	1,094	46	21	17
Total costs and expenses	577,737	332,120	88,969	56,129	61,640
Income (loss) before income taxes	99,043	(322,780)	(78,774)	(48,536)	(60,070)
Income tax expense (benefit)	76,686	(77,108)	973	269	718
Net income (loss)	$ 22,357	$ (245,672)	$ (79,747)	$ (48,805)	$ (60,788)
Accretion to redemption value of convertible preferred units	(24,442)	(77,313)	(51,528)	(21,449)	(8,505)
Net loss attributable to common shareholders/unit holders	$ (2,085)	$ (322,985)	$ (131,275)	$ (70,254)	$ (69,293)
Net income per share attributable to common shareholders, as restated(2):					
Basic (represents the period from May 16, 2011 to December 31, 2011)	$ 0.09				
Diluted (represents the period from May 16, 2011 to December 31, 2011)	$ 0.09				
Weighted average number of shares used to compute net income per share, as restated(2):					
Basic (represents the period from May 16, 2011 to December 31, 2011)	368,474				
Diluted (represents the period from May 16, 2011 to December 31, 2011)	368,607				

(1) Pursuant to the terms of our corporate reorganization that was completed simultaneously with the closing of the IPO, all of the

interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. based on these interests' relative rights as set forth in Kosmos

Energy Holdings' then-current operating agreement. This included convertible preferred units of Kosmos Energy Holdings which were redeemed upon the consummation of the qualified public offering (as defined in the operating agreement in effect prior to the IPO) into common shares of Kosmos Energy Ltd. based on the pre-offering equity value of such interests.

(2) See Notes 2 and 16 to the consolidated financial statements.

Consolidated Balance Sheets Information:

	As of December 31,				
	2011	2010	2009	2008	2007
	(In thousands)				
Cash and cash equivalents	$ 673,092	$ 100,415	$ 139,505	$ 147,794	$ 39,263
Total current assets	1,112,481	559,920	256,728	205,708	65,960
Total property and equipment	1,377,041	998,000	604,007	208,146	18,022
Total other assets	62,412	133,615	161,322	1,611	3,393
Total assets	2,551,934	1,691,535	1,022,057	415,465	87,375
Total current liabilities	339,607	482,057	139,647	68,698	28,574
Total long-term liabilities	1,191,601	845,383	287,022	444	—
Total convertible preferred units	—	978,506	813,244	499,656	167,000
Total shareholders' equity/unit holdings equity	1,020,726	(614,411)	(217,856)	(153,333)	(108,199)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	2,551,934	1,691,535	1,022,057	415,465	87,375

Consolidated Statements of Cash Flows Information:

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands)				
Net cash provided by (used in):					
Operating activities	$ 364,909	$ (191,800)	$ (27,591)	$ (65,671)	$ (17,386)
Investing activities	(385,140)	(589,975)	(500,393)	(156,882)	(58,161)
Financing activities	592,908	742,685	519,695	331,084	104,973

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors." The following discussion of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the notes thereto included elsewhere in this annual report on Form 10-K.

Overview

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 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.

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.

2011 Highlights

Ghana—Jubilee Field

During 2011, we had six liftings of oil totaling 5,971 Mbbls from the Jubilee Field Phase 1 production resulting in revenues of $666.9 million. Our average realized price per barrel was $111.70.

A total of 17 development wells have been drilled during 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.

Pursuant to the terms of the Jubilee UUOA, the unit participation interests are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest (participating interest in the Jubilee Unit) was increased from 23.50868% (our percentage after Tullow's acquisition of EO Group's interest in July 2011) to 24.07710%.

In December 2011, Tullow, as Unit Operator for and on behalf of the Jubilee Unit acquired the FPSO we are using to produce hydrocarbons from the Jubilee Field from MODEC, Inc. ("MODEC") for $754.5 million, or $202.6 million net to Kosmos. At the time of the acquisition of the FPSO, the 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. Prior to the acquisition of the FPSO, the Jubilee Unit leased the FPSO from MODEC and the associated costs were recorded as oil and gas production expense. The purchase price was recorded as an addition to oil and gas properties. In 2012 and future periods, these costs will be depleted on the unit of production method. The Jubilee Unit Operator became the operator of the FPSO, with MODEC providing services under an operations and maintenance agreement.

Ghana—WCTP Block exploration and appraisal activity

In 2011, the Teak-1, Teak-2 and Teak-3 wells intersected multiple oil, gas and natural gascondensate bearing reservoirs in Campanian and Turonian zones. Fluid samples recovered from the wells indicate an oil gravity of between 32 and 39 degrees API and natural gas condensate gravity of between 40 and 45 degrees API.

In June 2011, we announced that the Banda-1 exploration well had made a hydrocarbon discovery. We believe the target reservoir is a channel fairway that is stratigraphically trapped. The well intersected quantities of oil-bearing reservoirs in Cenomanian to Albian zones, although the well is considered sub-commercial. The Banda discovery represents a new play in the WCTP Block.

In August 2011, we announced the Akasa-1 exploration well had made a hydrocarbon discovery. Fluid samples recovered from the well indicates an oil gravity of 38 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 East 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. See "Item 1A. Risk Factors—We had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements."

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 Ghana 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.

Ghana—DT Block exploration and appraisal activity

In April 2011, the Tweneboa-4 appraisal well successfully confirmed the resource base potential of the Tweneboa Field. The well encountered gas-condensate pay in high-quality stacked reservoir sandstones. In January 2011, the Tweneboa-3ST well encountered net gas-condensate pay in high-quality stacked reservoir sandstones in two zones. We determined the sidetrack on the Tweneboa-3 encountered the Ntomme field, a separate discovery area.

In January 2012, the Ntomme-2A appraisal well confirmed a downdip extension of the Ntomme Field, which was discovered by the Tweneboa-3ST. The well encountered high-quality stacked reservoir sandstones. The well confirmed the majority of the resources in the discovery to be oil. Fluid samples recovered from the wells indicate an oil gravity of approximately 35 degrees API.

In May 2011 and August 2011, the Tweneboa-2 drill stem test flowed oil and the Tweneboa-4 drill stem test flowed natural gas condensate.

In March 2011, the Enyenra-2A appraisal confirmed a downdip extension of the Enyenra Field (formerly known as Owo), which was discovered by the Owo-1 exploration well. The Enyenra-2A well encountered oil and gas-condensate in high-quality stacked sandstone reservoirs. Results of drilling, wireline logs, reservoir fluid samples and pressure data show that the Enyenra-2A well intersected oil in the upper channel and lower channel. The Enyenra-2A well also tested a portion of a deeper reservoir where gas-condensate sandstones were intersected in the Tweneboa Deep discovery. Fluid samples recovered from the well indicate a natural gas condensate gravity of approximately 46 degrees API.

In September 2011, the Enyenra-3A appraisal well confirmed an updip extension of the Enyenra light oil field. Analysis of well results, including wireline logs, reservoir pressures and fluid samples indicated the Enyenra-3A well encountered oil-bearing pay. Fluid samples recovered from the well indicate an oil gravity of approximately 35 degrees API.

The first extension period of the exploration phase of the DT Block expired on January 19, 2011. In accordance with the DT PA, Tullow, on behalf of the DT Block partners, formally extended the DT PA into the second extension period and relinquished 25% of the DT Block. The seven-year exploration phase of the DT PA will expire in January 2013. Our existing discoveries within the DT Block are not subject to relinquishment upon expiration of the exploration phase of the DT PA, as the DT PA remains in effect after the end of the exploration phase, and these are Tweneboa, Enyenra and Ntomme. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum contract and certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area. We and our DT Block partners exercised such right to negotiate a new petroleum contract in January 2012.

Morocco

During 2011, we increased our acreage positions offshore the Kingdom of Morocco by acquiring two new petroleum contracts, renewing an existing petroleum contract and acquiring a new reconnaissance contract. Our exploration licenses include Cap Boujdour Offshore Block, which is within the Aaiun Basin, and Essaouira Offshore Block and Foum Assaka Offshore Block, which are within the Agadir Basin. Our reconnaissance contract is over the Tarhazoute Offshore area within the Agadir Basin. Kosmos is the operator of the blocks and has a 75% participating interest in the Cap Boujdour Offshore Block, a 37.5% participating interest in the Essaouira Offshore Block and Foum Assaka Offshore Block, and a 100% interest in the reconnaissance contract covering the Tarhazoute Offshore area. Upon receipt of approval from the Moroccan government, we will acquire an additional 18.75% participating interest in the Foum Assaka Offshore Block from Pathfinder Hydrocarbon Ventures Ltd., one of our block partners.

We are currently acquiring a 4,800 square kilometer 3D seismic data acquisition program in the Agadir Basin. Approximately half of the data to be acquired covers the Essaouira Offshore Block with the remainder in the Foum Assaka Block.

Cameroon

In an order dated March 3, 2011, the Minister of Industry, Mines and Technology Development confirmed our entry into the first renewal period of the Ndian River petroleum contract.

In January 2012, Kosmos entered into a license with Cameroon for the Fako Block. Kosmos is the operator and has a 100% participating interest in the block. The block covers 318,519 acres(1,289 square kilometers) and borders the southeast portion of our Ndian River Block in the Rio del Rey Basin.

Suriname

Kosmos' new ventures effort extended beyond our historical West Africa focus area as we entered into two Production Sharing Contracts in South America. In December 2011, Kosmos entered into Production Sharing Contracts for Blocks 42 and 45 offshore Suriname. Kosmos is the operator and has a 100% participating interest in Suriname offshore Block 42 and a 100% participating interest in Suriname offshore Block 45.

Results of Operations

All of our results from operations relates to production from the Jubilee Field in Ghana. Certain operating results and statistics for the comparative years of 2011, 2010 and 2009 are included in the following table:

	Years Ended December 31,		
(In thousands, except per barrel data)	**2011**	**2010**	**2009**
Sales volumes:			
Mbbls	5,971	—	—
Revenues:			
Oil sales	$ 666,912	$ —	$ —
Average sales price per bbl	111.70	—	—
Costs:			
Oil production	$ 83,551	$ —	$ —
Depletion	135,532	—	—
Average oil production cost per bbl	$ 13.99	$ —	$ —
Average depletion cost per bbl	22.70	—	—
Average oil production cost and depletion per bbl	$ 36.69	$ —	$ —

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

Year Ended December 31, 2011 vs. 2010

	Years Ended December 31, 2011	2010	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 666,912	$ —	$ 666,912
Interest income	9,093	4,231	4,862
Other income	775	5,109	(4,334)
Total revenues and other income	676,780	9,340	667,440
Costs and expenses:			
Oil and gas production	83,551	—	83,551
Exploration expenses, including dry holes	126,409	73,126	53,283
General and administrative	113,579	98,967	14,612
Depletion and depreciation	140,469	2,423	138,046
Amortization—deferred financing costs	16,193	28,827	(12,634)
Interest expense	65,749	59,582	6,167
Derivatives, net	11,777	28,319	(16,542)
Loss on extinguishment of debt	59,643	—	59,643
Doubtful accounts expense	(39,782)	39,782	(79,564)
Other expenses, net	149	1,094	(945)
Total costs and expenses	577,737	332,120	245,617
Income (loss) before income taxes	99,043	(322,780)	421,823
Income tax expense (benefit)	76,686	(77,108)	153,794
Net income (loss)	$ 22,357	$ (245,672)	$ 268,029

Oil and gas revenue. During the year ended December 31, 2011, we recorded oil revenues of $666.9 million due to oil production from the Jubilee Field. We lifted and sold approximately 5,971 Mbbls at an average realized price per barrel of $111.70. In 2010, we had no oil sales and, therefore, no associated revenues.

Interest income. Interest income increased by $4.9 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to interest on notes receivable. The related note receivable was retired in December 2011 as part of the acquisition of the FPSO we are using to produce hydrocarbons from the Jubilee Field.

Other income. Other income decreased by $4.3 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to a decrease in technical services fees and overhead charges billed to the Unit Operator for services provided on the Jubilee Field Phase 1 development.

Oil and gas production. During the year ended December 31, 2011, we recorded oil and gas production costs of $83.6 million related to oil production from the Jubilee Field. Our average production cost per barrel was $13.99. In 2010, there were no oil sales and, therefore, no associated oil and gas production costs.

Exploration expenses. Exploration expenses increased by $53.3 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010. During the year ended December 31, 2011, we incurred $32.8 million for seismic costs and $91.3 million of unsuccessful well costs, primarily related to the Cameroon N'gata-1, Ghana Makore-1, Ghana Banda-1 and Ghana Odum exploration wells. During the year ended December 31, 2010, the Company incurred $59.4 million of unsuccessful well costs primarily related to the Ghana Dahoma-1 and Cameroon Mombe-1 wells and $13.0 million for seismic costs.

General and administrative. General and administrative costs increased by $14.6 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to an increase in staffing and increases in non-cash expenses of $37.2 million for equity-based compensation, partially offset by decreases in cash expenses for professional fees. Total non-cash general and administrative costs were $51.0 million and $13.8 million for the years ended December 31, 2011 and 2010, respectively.

Depletion and depreciation. Depletion and depreciation increased $138.0 million during the year ended December 31, 2011, as compared with the year ended December 31, 2010, due to production from the Jubilee Field. In 2010, there were no oil sales and, therefore, no associated depletion.

Amortization—deferred financing costs and Loss on extinguishment of debt. During the year ended December 31, 2011, we incurred approximately $52.3 million of deferred financing costs as part of our debt refinance, in addition to our existing unamortized deferred financing costs of $68.6 million. As a result of the debt refinance, 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. The related amortization of deferred financing costs decreased by $12.6 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, due to the decrease in capitalized deferred financing costs and the longer term associated with the Facility.

Interest expense. Interest expense increased by $6.2 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to a decrease in capitalized interest and higher average outstanding debt during the year ended December 31, 2011.

Derivatives, net. Derivatives, net decreased $16.5 million during the year ended December 31, 2011, as compared with December 31, 2010, due to the change in fair value of the commodity derivative instruments.

Doubtful accounts expense. During the year ended December 31, 2011, we released a $39.8 million allowance for doubtful accounts related to a receivable previously in default. We received the full amount of the receivable during the third quarter of 2011.

Income tax expense (benefit). The Company recognized an income tax provision attributable to earnings of $76.7 million during 2011 and an income tax benefit of $77.1 million during 2010. The Company's effective tax rates for 2011 and 2010 were 77.4% and 23.9%, respectively. The large variance in income taxes between 2011 and 2010 is due to the release of the Ghana valuation allowance in 2010. The large effective tax rate in 2011 is primarily due to the fact that no tax benefit is currently being provided on losses in jurisdictions with a full valuation allowance and jurisdictions where no income tax is assessed.

Year Ended December 31, 2010 vs. 2009

	Years Ended December 31 2010	2009	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Interest income	4,231	985	3,246
Other income	5,109	9,210	(4,101)
Total revenues and other income	9,340	10,195	(855)
Costs and expenses:			
Exploration expenses, including dry holes	73,126	22,127	50,999
General and administrative	98,967	55,619	43,348
Depletion, depreciation and amortization	2,423	1,911	512
Amortization—deferred financing costs	28,827	2,492	26,335
Interest expense	59,582	6,774	52,808
Derivatives, net	28,319	—	28,319
Doubtful accounts expense	39,782	—	39,782
Other expenses, net	1,094	46	1,048
Total costs and expenses	332,120	88,969	243,151
Loss before income taxes	(322,780)	(78,774)	(244,006)
Income tax expense (benefit)	(77,108)	973	(78,081)
Net loss	$ (245,672)	$ (79,747)	$ (165,925)

Oil and gas revenue. We commenced oil and natural gas production on November 28, 2010 and received our first revenues from such production in early 2011; therefore, we did not realize any oil and gas revenue during the years ended December 31, 2010 and 2009.

Interest income. Interest income increased by $3.2 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to interest accrued on receivables—joint interest billings, as we had a higher outstanding receivable balance in 2010.

Other income. Other income decreased by $4.1 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, primarily due to a decrease in technical services fees and overhead charges billed to the Unit Operator as a result of the Jubilee Field Phase 1 development nearing completion.

Exploration expenses. Exploration expenses increased by $51.0 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, primarily due to unsuccessful well costs of $28.4 million and $26.0 million for the Ghana Dahoma-1 well and Cameroon Mombe-1 well, respectively, and an increase in purchases of seismic data for Ghana of $5.6 million offset by a decrease in purchases of seismic data for Morocco of $12.9 million.

General and administrative. General and administrative costs increased by $43.3 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to non-recurring charges of approximately $23.0 million, which includes a $15.0 million accrual that was payable upon the successful completion of our IPO pursuant to our settlement agreement entered into with GNPC and the Government of Ghana in December 2010, increases in professional fees and expenses of $6.1 million, unit-based compensation of $10.4 million and operator charges of $4.3 million, offset in part by increases in capitalized technical service fees of $4.4 million.

Amortization—deferred financing costs. Amortization—deferred financing costs increased by $26.3 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to the amortization of the fees which were capitalized in connection with the initial draw on the commercial debt facilities in November 2009.

Interest expense. Interest expense increased by $52.8 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, $49.6 million due to draws on the commercial debt facilities beginning in November 2009 and $12.4 million for realized and unrealized losses on interest rate swaps offset by an increase of $9.2 million in capitalized interest.

Derivatives, net. During the year ended December 31, 2010, we recorded $28.3 million of unrealized losses on commodity derivatives, due to exposure to continuing market risk.

Doubtful accounts expense. During the year ended December 31, 2010, we recorded an allowance for doubtful accounts of $39.8 million, related to a receivable in default which became due upon the commencement of oil production from the Jubilee Field in November 2010. Based on this default, we established an allowance to cover our estimated exposures.

Income tax expense (benefit). Income tax decreased by $78.1 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to the release of the Ghana valuation allowance at December 31, 2010.

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. Accordingly, the cash flows generated from our operating activities may provide an additional source of future funding.

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.

As of December 31, 2011, borrowings under the Facility totaled $1.1 billion. As of December 31, 2011, the undrawn availability under the Facility was an additional $153.0 million. As of January 9, 2012, the undrawn availability under the Facility was reduced to $128.0 million.

In February 2012, the Company amended the Facility. The terms and conditions of the Facility remained consistent with the original terms and conditions, however, the International Finance Corporation entered the Facility. The total commitment under the Facility remained unchanged at $2.0 billion.

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 $3.0 million of additional interest expense during the year ended December 31, 2011, and zero for each of the years ended December 31, 2010 and 2009.

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 is also constrained by the amortization schedule (once repayments under the Facility begin). Beginning on 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, is 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. 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 percentages.

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 December 15, 2011, 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,

in each case, as calculated on the basis of all available information. 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.

The U.S. and many foreign economies continue to experience uncertainty driven by varying macroeconomic conditions. Although some of these economies have shown signs of improvement, macroeconomic recovery remains uneven. Uncertainty in the macroeconomic environment and associated global economic conditions have resulted in extreme volatility in credit, equity, and foreign currency markets, including the European sovereign debt markets and volatility in various markets. If any of the financial institutions within our Facility are unable to perform on their commitments, our liquidity could be impacted. See "Item 1A. Risk Factors—Our operations may be adversely affected by the European debt crisis." We actively monitor all of the financial institutions participating in our Facility. None of the financial institutions have indicated to us that they may be unable to perform on their commitments. In addition, we periodically review our banking and financing relationships, considering the stability of the institutions and other aspects of the relationships. Based on our monitoring activities, we believe our banks will be able to perform on their commitments.

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.

We generated revenues of $666.9 million in 2011 from our oil sales from the Jubilee Field.

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 estimate we will incur approximately $600 million of capital expenditures for the year ending December 31, 2012. The estimated capital expenditures of $600 million exclude the estimated costs associated with the potential purchase of Sabre's 4.05% participating interest in the DT Block of approximately $365.0 million, with up to $45.0 million in contingent payments upon achieving certain performance milestones. This 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.

The following table presents our liquidity and financial position as of December 31, 2011:

	December 31, 2011
	(In thousands)
Cash	$ 673,092
Drawings under the commercial debt facility	1,110,000
Net debt	436,908
Total of unused borrowing base	153,000
Unused borrowing base plus cash	826,092

Cash Flows

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Net cash provided by (used in):			
Operating activities	$ 364,909	$ (191,800)	$ (27,591)
Investing activities	(385,140)	(589,975)	(500,393)
Financing activities	592,908	742,685	519,695

Operating activities. Net cash provided by operating activities in 2011 was $364.9 million compared with net cash used in operating activities of $191.8 million and $27.6 million in 2010 and 2009, respectively. The increase in cash provided by operating activities in 2011 when compared to 2010 was primarily due to sales of oil from the Jubilee Field production and working capital changes. The increase in cash used in 2010 when compared to 2009 is mainly due to changes in working capital related to receivables of $66.1 million, primarily joint interest billings, timing of payments of $15.1 million, prepaid drilling costs of $12.5 million, increases in interest expense of $45.7 million and $28.3 million of general and administrative expenses.

Investing activities. Net cash used in investing activities in 2011 was $385.1 million compared with $590.0 million and $500.4 million in 2010 and 2009, respectively. The decrease in cash used in 2011 when compared to 2010 was primarily attributable to changes in restricted cash, notes receivable and expenditures for oil and gas assets primarily in Ghana for development activities. The increase in cash used in 2010 when compared to 2009 was primarily attributable to increases in restricted cash of $29.0 million related to the commercial debt facilities, $23.0 million for the cash collateralized irrevocable letter of credit associated with the Eirik Raude drilling rig and an increase of $32.8 million in expenditures for oil and gas assets primarily in Ghana for exploration and appraisal wells and development activities.

Financing activities. Net cash provided by financing activities in 2011 was $592.9 million compared with $742.7 million and $519.7 million in 2010 and 2009, respectively. The decrease in cash provided in 2011 when compared to 2010 was due to net proceeds from the IPO of $580.4 million offset by lower net borrowings on the commercial debt facilities of $695.0 million and a $35.2 million increase in cash used for deferred financing costs. The increase in cash provided in 2010 when compared to 2009 is primarily due to increased borrowings of $475.0 million on the commercial debt facilities offset by a decrease of $73.3 million in cash used for deferred financing costs and a decrease of $325.3 million of proceeds from the issuances of Series B and Series C Convertible Preferred Units.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2011:

	Payments Due By Year(4)						
	Total	2012	2013	2014	2015	2016	Thereafter
	(In thousands)						
Drilling rig contract(1)	$ 137,168	$137,168	$ —	$ —	$ —	$ —	$ —
Operating leases	21,797	234	2,821	2,921	3,022	3,122	9,677
Commercial debt facility(2)	1,110,000	—	—	—	110,000	444,444	555,556
Interest payments on commercial debt facility(3)	311,936	48,202	50,631	55,012	62,362	61,145	34,584

(1) Does not include any well commitments we may have under our oil and natural gas licenses.

(2) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2011. 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.

(3) Based on outstanding borrowings as noted in (2) above and six month LIBOR yield curves at the reporting date.

(4) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes $19.1 million of commitments for exploration activities in our petroleum contracts.

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.

	Year Ending December 31,						Asset (Liability) Fair Value at December 31, 2011
	2012	2013	2014	2015	2016	Thereafter	
	(In thousands, except percentages)						
Variable rate debt:							
Commercial debt facility maturities	$ —	$ —	$ —	$110,000	$444,444	$555,556	$(1,110,000)
Weighted average interest rate	4.34%	4.56%	4.96%	5.62%	6.88%	7.39%	
Interest rate swaps:							
Notional debt amount(1)	$138,073	$91,683	$47,033	$ 16,875	$ 6,250	$ —	$ (3,636)
Fixed rate payable	2.22%	2.22%	2.22%	2.22%	2.22%		
Variable rate							

Variable rate receivable(2)	0.83%	0.91%	1.11%	1.70%	2.10%		
Notional debt amount(1)	$138,073	$91,683	$47,033	$ 16,875	$ 6,250	$ —	$ (3,908)
Fixed rate payable	2.31%	2.31%	2.31%	2.31%	2.31%		
Variable rate receivable(2)	0.83%	0.91%	1.11%	1.70%	2.10%		
Notional debt amount(1)	$ 63,625	$19,057	$ 1,868	$ —	$ —	$ —	$ (107)
Fixed rate payable	0.98%	0.98%	0.98%				
Variable rate receivable(2)	0.83%	0.91%	0.99%				
Notional debt amount(1)	$ 50,942	$24,680	$38,434	$ 23,137	$ —	$ —	$ (423)
Fixed rate payable	1.34%	1.34%	1.34%	1.34%			
Variable rate receivable(2)	0.83%	0.91%	1.11%	1.57%			

(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.

Off-Balance Sheet Arrangements

As of December 31, 2011, we did not have any off-balance sheet arrangements.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities as of the date the financial statements are available to be issued. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual audited results may vary from our estimates. Our significant accounting policies are detailed in "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies." We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance.

Exploration and Development Costs. We follow the successful efforts method of accounting for our oil and gas properties. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when a determination that proved reserves have been found. Exploration costs, including geological and geophysical costs and costs of carrying unproved properties, are charged to expense as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift crude oil and natural gas to the surface are expensed.

Receivables. Our receivables consist of joint interest billings, oil sales, notes and other receivables for which we generally do 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 a perfected lien against the $61.7 million account receivable for which we established a $39.8 million allowance for doubtful accounts as of December 31, 2010 and, therefore, did not consider the future net revenues in our assessment of the collectability of the receivable. During 2011, we received full repayment of the long-term joint interest billing receivable and the related valuation allowance of $39.8 million was reversed during the second quarter of 2011. Details concerning such account receivable are as follows.

The agreement between Kosmos and EO Group dated June 1, 2004 (the "EO Participation Agreement") created Kosmos' obligation to pay EO Group's 3.5% share of costs (the "EO Carry") under the WCTP PA. Under the EO Participation Agreement, Kosmos is entitled to reimbursement for the development capital expenditures paid for EO Group (the "EO Development Costs"). The EO Participation Agreement also provided for the termination of the EO Carry on commencement of production from the WCTP Block, which occurred on November 28, 2010. Thereafter, EO Group was obligated to (i) pay their share of costs under the WCTP PA pursuant to the joint operating agreement for the WCTP Block among the WCTP Block partners ("WCTP JOA"), due to termination of the EO Carry; and (ii) reimburse Kosmos for EO Development Costs in the amount of $61.7 million. However, shortly thereafter, EO Group did not pay its share of WCTP JOA costs, was declared in default under the WCTP JOA in December 2010 and remained in default; with an unpaid balance of $3.7 million as of December 31, 2010. Each non-defaulting party was obligated to pay its proportionate share of the EO Group's default amounts and did so. EO Group did not reimburse Kosmos for the $61.7 million in EO Development Costs and accordingly was in default under the EO Participation Agreement as of December 31, 2010.

As a defaulting party under the WCTP JOA, EO Group would lose its right to sell its share of oil production which would instead be sold by the non-defaulting parties to repay the default amounts paid by the non-defaulting parties. If the default was not remedied within 60 days, EO Group could have been required to withdraw from the WCTP PA and the WCTP JOA and forfeited its interest to the non-defaulting parties (subject to the Government of Ghana's consent to such "transfer"). If such forfeiture occurred, the non-defaulting parties would have proportionately own EO Group's interest in the WCTP PA. However, a potential forfeiture could be disputed by EO Group in international arbitration under the WCTP JOA and further, enforcement would be subject to the discretion of English courts. Furthermore, the non-defaulting parties did not exercise the right to require EO Group's withdrawal and forfeiture from the WCTP PA; but instead agreed at that time to hold off exercising such right, after becoming aware of a potential sale of EO Group's interest in the WCTP PA. As the non-defaulting parties had the right to sell EO Group's share of oil production to repay default amounts paid by such non-defaulting parties, we believed any buyer would seek to cure any defaults in connection with any purchase of the EO Group's interest in the WCTP PA so as to enable the buyer to exercise the right to sell the corresponding share of oil. As a result of this belief and the non-defaulting parties ability to repay default amounts owed to them through the sale of EO Group's share of oil production, we did not establish an allowance for doubtful accounts as of December 31, 2010 for EO Group's default under the WCTP JOA.

At December 31, 2010, our ability to collect the $61.7 million owed to Kosmos under the EO Participation Agreement by the EO Group depended on the EO Group's ability to sell its share of the Jubilee oil production or sell all or part of their interest in the WCTP PA. Because EO Group's share of production was being sold by the non-defaulting parties to pay EO Group's share of WCTP JOA costs (as discussed in the paragraph above), EO Group had not made any payments to reimburse Kosmos for the EO Development Costs. Unlike the WCTP JOA, the EO Participation Agreement did not provide specific remedies should EO Group fail to reimburse the EO Development Costs and such was not contemplated in 2004. If Kosmos was not paid, Kosmos would have a contractual claim against EO Group for the amounts owed under the EO Participation Agreement and our recourse would have been to international arbitration. While we may have prevailed in such arbitration, our ability to fully collect under an arbitral award would have been uncertain due to the EO Group likely not having the financial means to satisfy any such award as well as any enforcement thereof being subject to the discretion of the English courts. However, under the WCTP JOA, Kosmos had a pro rata right of first refusal to buy EO Group's interest in the WCTP PA should EO Group seek to sell such interest. As stated above, we had recently become aware of a potential sale of EO Group's interest in the WCTP PA. While the right of first refusal did not entitle us to withhold consent to any sale, we believed the existence of such right may provide commercial leverage in the sale process such that EO Group or any buyer of their interests would pay Kosmos the amounts owed under the EO Participation Agreement in connection with such sale. We believed a buyer may be hesitant to purchase an asset such as EO Group's interest in the WCTP PA unless unresolved claims, such as our claim to be reimbursed for the EO Development Costs, were resolved. Furthermore, we believed that it is not uncommon for buyers of assets subject to rights of first refusals to require such rights to be preemptively waived to ensure the smooth execution of the purchase process. While we believed these factors would aid us in recovering amounts owed, without an absolute right to withhold consent to any sale of EO Group's interest, recovery through this method was not assured. Accordingly, we did not bring a breach of contract dispute in an international arbitration proceeding against EO Group for their default under the EO Participation Agreement as we were attempting to resolve this matter amicably by affording EO Group time to arrange the potential sale of all or part of their interest in the WCTP PA.

After consideration of the circumstances outlined above, we determined the EO Development Costs were not fully collectible at December 31, 2010 and estimated our range of loss to be between 50% to 75% of the balance. $39.8 million (approximately 65%) of the $61.7 million EO Development Costs represents our best estimate of the potential uncollectible amounts at December 31, 2010. In determining our best estimate of the recoverable amount and the reserve amount, we considered a number of factors that included, but were not limited to, the following: the uncertainty in enforcing our reimbursement right under the EO Participation Agreement in international arbitration, discussions held with EO Group regarding recovery of amounts owed and their current ability to pay such amounts, the commercial leverage we believe is afforded under our pro rata right of first refusal discussed above, EO Group's lack of access to funds as evidenced by their inability to pay their share of WCTP JOA costs upon commencement of production on November 28, 2010 and their subsequent default, and the fact that our ability to collect the amounts owed to us by EO Group was dependent on either their ability to sell their share of Jubilee oil production or sell all or part of their interest in the WCTP PA. However, the $39.8 million reserve for uncollectible debt at December 31, 2010 reflected our best estimate of what amounts we actually would be able to recover. During 2011, Tullow acquired EO Group's interest in the WCTP Block and we received the $61.7 million receivable due from EO Group. The allowance for doubtful accounts of $39.8 million was reversed when the transaction occurred.

Income Taxes. We account for income taxes as required by the ASC 740—Income Taxes ("ASC 740"). We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal, state and international tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to realize or utilize our deferred tax assets. If realization is not more likely than not, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in no benefit for the deferred tax amounts. As of December 31, 2011 and 2010, we have a valuation allowanceto reduce certain deferred tax assets to amounts that are more likely than not to be realized. If our estimates and judgments regarding our ability to realize our deferred tax assets change, the benefits associated with those deferred tax assets may increase or decrease in the period our estimates and judgments change. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax asses and adjusts the amount of such allowances, if necessary.

The Company had net deferred tax assets in Ghana totaling approximately $20.6 million at December 31, 2009 primarily relating to capitalized operating expenses incurred during the development phase of the Jubilee Field. Prior to the commencement of production from the Jubilee Field on November 28, 2010, the Company maintained a full valuation allowance against its net deferred tax asset. However, at December 31, 2010, the Company determined that it was more likely than not that the deferred tax asset for its Ghana operations would be recognized, resulting in the valuation allowance no longer being necessary. Therefore, we released the $20.6 million deferred tax asset valuation allowance and recognized $56.9 million of deferred tax assets generated during 2010.

The factors that the Company considered are discussed below. Based on these factors, the Company concluded that many of the considerations that previously led to the need for a valuation allowance related to the Ghana deferred tax assets no longer existed as of December 31, 2010.

In determining that a valuation allowance was not needed for the Ghanaian deferred tax assets at December 31, 2010 we considered the requirements of ASC 740, including that all evidence, both positive and negative, should be considered to determine whether, based on all the weight of the available evidence, it is more-likely-than-not a deferred tax asset will or will not be realized. If it is more-likely-than-not that the deferred tax asset will be realized, a valuation allowance is not needed. In performing this assessment for the Ghanaian deferred tax assets, the Company determined that the factors that led to the creation of deferred tax assets while operating as a development stage entity changed significantly when the Company moved into the production phase. We considered the following evidence in assessing the realizability of the net deferred tax asset as of December 31, 2010:

- The commencement of oil production on November 28, 2010. Equipment and infrastructure was fully in place in the fourth quarter of 2010 immediately prior to production commencing, and the November 28, 2010 successful commencement of production confirmed our expectations that these assets could be utilized to successfully produce from the field with an economical cost structure.

- The recognition of our first revenues from oil production in January 2011. The Company was a development stage entity as of December 31, 2010, but upon recognition of our first revenues in January 2011, was no longer categorized as such.

- The existence of significant proved reserves that had been independently verified.

- The Company was producing a commodity (crude oil) with observable market demand capable of purchasing all barrels produced. Prices for oil could be estimated through forward pricing curves.

- The ability to recover our deferred tax assets based on our projections, at such time, of taxable income for future years. Production volumes utilized in our projection were based on our proved reserve estimates as of December 31, 2010, which had been independently verified, and our schedule for production which was approved by the Jubilee Unit partners, and forecasted increased production during 2011 and future periods. Prices were estimated based on prices utilized to calculate our standardized measure as of December 31, 2010. We estimated our expenses based on current contracts and cost structures in place at that time. Based on the production plan and a price per barrel of $79.35, which is also used to calculate our standardized measure as of December 31, 2010, we anticipated realization of the net operating loss carryforward by the end of 2012.

- The excess of appreciated asset value over the tax basis of our Ghanaian net assets of an amount sufficient to realize the deferred tax asset. Our estimates of the excess of the appreciated asset value were based upon the independently verified reserve report, third party offers for our Ghana assets, and other market indicators.

- We tested the sensitivity of our projection of taxable income to changes in production volumes and prices, which indicated that future taxable income was sufficient to recover the deferred tax assets under various scenarios.

  Our projection of taxable income at December 31, 2010 was based on a per barrel price of $79.35, which is also used to calculate our standardized measure, and our production forecast, which is based on our proved reserve estimates and our schedule for production. Based on this projection, we estimated that we would utilize our $295.9 million net operating loss carryforward before the end of 2012. Assuming a 25% decrease in prices or volumes, we estimated that we would utilize our $295.9 million net operating loss carryforward before the end of 2013. Assuming a 25% decrease in prices and volumes, we estimated that we would utilize our $295.9 million net operating loss carryforward before the end of 2015. Assuming a decrease in the price of oil to $50 per barrel and no change in anticipated production volumes, we estimated that we would utilize our $295.9 million net operating loss carryforward before the end of 2015. A $50 per barrel price represents an average price per barrel lower than the average price during 2008 and 2009 when oil prices sustained substantial price declines and a 57% decrease from the Dated Brent price of $116.45 per barrel on March 2, 2011. Conversely, assuming a 25% increase in prices (or $99.19 per barrel which would still be less than the $116.45 per barrel price of Dated Brent on March 2, 2011, the date of our financial statements for the year ended December 31, 2010) and no change in volume, we estimated that we would utilize our $295.9 million net operating loss carryforward before the end of 2011.

- There is an unlimited net operating loss carryforward period under Ghanaian tax law, which provides flexibility in utilization of the net operating loss.

ASC 740 provides a more-likely-than-not standard in evaluating whether a valuation allowance is necessary after weighing all of the available evidence. Using the more-likely-than-not standard and weighing all available positive and negative evidence, the Company believed that, as of December 31, 2010, considering the facts and circumstances at that time, the negative evidence of the cumulative losses incurred during the development stage was overcome by the positive evidence relating to the Company's ability to more-likely-than-not realize the deferred tax assets in Ghana. Accordingly, we determined that it was more likely than not that the deferred tax asset for our Ghanaian operations would be realized at December 31, 2010. For the year ended December 31, 2011, we expect to utilize approximately $164.0 million of our net operating loss carryforward, which supports our determination on the realizability of our deferred tax assets as of December 31, 2011.

As of December 31, 2011, our Ghana operations had a net deferred tax asset of approximately $4.2 million and are no longer in a three year cumulative loss position. In consideration of the realizability of our net deferred tax asset as of December 31, 2011, we considered the following, in addition to the aforementioned positive evidence:

- Our operations subject to taxation in Ghana are no longer in a three year cumulative loss position.

- For the year ended December 31, 2011, we expect to utilize approximately $164.0 million of our net operatingloss carryforward.

- The ability to recover our deferred tax assets based on our projections of taxable income for future years. Production volumes utilized in our projection were based on our proved reserve estimates as of December 31, 2011, which have been independently verified, and our schedule for production which was approved by the Jubilee Unit partners, and forecasted for increased production during 2012 and future periods. Prices were estimated based on prices utilized to calculate our standardized measure as of December 31, 2011. We estimated our expenses based on current contracts and cost structures in place at that time. Based on such projections, we estimate that we will utilize the remainder of the net operating loss during 2012.

Based on our analysis, we concluded that it is more-likely-than-not that our remaining Ghana deferred tax asset as of December 31, 2011 will be realized in the future.

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 deferred premium puts and compound options (calls on puts). We also use interest rate swap contracts to mitigate our exposure to interest rate fluctuations related to our commercial debt facilities. 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 and accordingly the changes in the fair value of the instruments are recognized in earnings in the period of change.

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 which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of these reserve estimates is a function of:

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

Asset Retirement Obligations. We account for asset retirement obligations as required by the ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion and depreciation in the consolidated statement of operations. Estimating the future restoration and removal costs requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Additionally, asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is generally made to the oil and gas property balance.

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

New Accounting Pronouncements

In May 2011, the FASB issued ASU No. 2011-04, "Amendments to Achieve Common Fair Value Measurement andDisclosure Requirements in U.S. GAAP and IFRSs," to develop common requirements for valuation and disclosure of fair value measurements in accordance with U.S. GAAP and International Financial Reporting Standards. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income," to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. In December 2011, the FASB issued ASU No. 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." ASU No. 2011-12 defers certain reporting requirements ASU No. 2011-05. We do not expect the adoption of ASU 2011-05 and ASU 2011-12 will have a material effect on our consolidated financial statements.

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 affects 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.

Item 7A. Qualitative and Quantitative Disclosures About Market Risk

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

We manage and control market and counterparty credit risk in accordance with policies and guidelines approved by our Board of Directors. In accordance with these policies and guidelines, our executive management determines 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 "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies, Note 10—Derivative Financial Information and Note 11—Fair Value Measurements" for a description of the accounting procedures we follow relative to our derivative financial instruments.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the year ending December 31, 2011:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
		(In thousands)	
Fair value of contracts outstanding as of December 31, 2010	$ (28,319)	$ (5,638)	$ (33,957)
Changes in contract fair value	(11,777)	(9,548)	(21,325)
Contract maturities	15,336	7,112	22,448
Fair value of contracts outstanding as of December 31, 2011	$ (24,760)	$ (8,074)	$ (32,834)

Commodity Derivative Instruments

In 2010, we entered into various oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production. These contracts consisted of deferred premium puts and compound options (calls on puts).

Commodity Price Sensitivity

The following tables provide information about our oil derivative financial instruments that were sensitive to changes in oil prices as of December 31, 2011.

	Bbl/day	Weighted Average Floor Price	Weighted Average Deferred Premium/bbl	Liability Fair Value at December 31, 2011
Oil derivatives:				
Deferred premium puts				
January 2012—December 2012	4,625	$ 62.74	$ 7.04	
January 2013—December 2013	2,515	$ 61.73	$ 7.32	
Total fair value of deferred premium puts(1)				$ 17,677
Compound options (calls on puts)(2)				
July 2012—December 2012	5,399	$ 66.48	$ 6.73	
January 2013—June 2013	3,855	$ 66.48	$ 7.10	
Total fair value of compound options(1)				$ 7,083

(1) Fair values are based on the average forward Dated Brent oil prices on December 31, 2011 which by year are: 2012—$105.28 and 2013—$100.89. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on February 20, 2012 market quotes by year are: 2012—$117.47 and 2013—$111.32.

(2) The calls expire June 29, 2012 and have a weighted average premium of $4.82/bbl.

Interest Rate Derivative Instruments

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

Interest Rate Sensitivity

At December 31, 2011, we had indebtedness outstanding under the Facility of $1.1 billion, of which $635 million bore interest at floating rates. The weighted average interest rate on this indebtedness as of December 31, 2011 was approximately 4.2%. 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 the Facility.

As of December 31, 2011, the fair market value of our interest rate swaps was a net liability of approximately $8.1 million. If LIBOR increased by 10%, we estimate the liability would decrease to approximately $7.3 million, and if LIBOR decreased by 10%, we estimate the liability would increase to approximately $8.8 million.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Kosmos Energy Ltd.

We have audited the accompanying consolidated balance sheets of Kosmos Energy Ltd. as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity/unit holdings equity, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules included at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Kosmos Energy Ltd. and subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the consolidated financial statements taken as a whole, present fairly, in all material respects, the financial information set forth therein.

As discussed in Note 2, the consolidated financial statements for the year ended December 31, 2011 have been restated to present net income per share attributable to common shareholders for the period from May 16, 2011 to December 31, 2011 instead of pro forma net income per share attributable to common shareholders for the period from January 1, 2011 to December 31, 2011.

/s/ Ernst & Young LLP

Dallas, Texas
March 1, 2012, except as to the presentation of net income
per share attributable to common shareholders
as discussed in Notes 2 and 16,
as to which the date is January 28, 2013.

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 673,092	$ 100,415
Restricted cash	23,747	80,000
Receivables:		
Joint interest billings	199,699	124,449
Oil sales	109,475	—
Notes	—	113,889
Other	981	615
Inventories	27,101	37,674
Prepaid expenses and other	13,913	13,278
Current deferred tax assets	64,473	89,600
Total current assets	1,112,481	559,920
Property and equipment:		
Oil and gas properties, net of accumulated depletion of $135,622 and $6,430, respectively	1,367,265	989,869
Other property, net of accumulated depreciation of $8,068 and $5,343, respectively	9,776	8,131
Property and equipment—net	1,377,041	998,000
Other assets:		
Restricted cash	3,800	32,000
Long-term receivables—joint interest billings, net of allowance of zero and $39.8 million, respectively	—	21,897
Deferred financing costs and other assets, net of accumulated amortization of $6,582 and $32,093, respectively	54,847	78,217
Long-term deferred tax assets—net	3,765	—
Derivatives	—	1,501
Total assets	$ 2,551,934	$ 1,691,535
Liabilities and shareholders' equity/unit holdings equity		
Current liabilities:		
Current maturities of long-term debt	$ —	$ 245,000
Accounts payable	278,006	163,495
Accrued liabilities	37,194	53,208
Derivatives	24,407	20,354
Total current liabilities	339,607	482,057
Long-term liabilities:		
Long-term debt	1,110,000	800,000
Derivatives	8,427	15,104
Asset retirement obligations	20,670	16,752
Deferred tax liability	47,608	12,513
Other long-term liabilities	4,896	1,014
Total long-term liabilities	1,191,601	845,383
Convertible preferred units, 100,000,000 units authorized:		
Series A—zero and 30,000,000 units issued at December 31, 2011 and 2010, respectively	—	383,246
Series B—zero and 20,000,000 units issued at December 31, 2011 and 2010, respectively	—	568,163
Series C—zero and 884,956 units issued at December 31, 2011 and 2010, respectively	—	27,097
Shareholders' equity/unit holdings equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2011 and 2010	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 390,530,946 and zero issued at December 31, 2011 and 2010, respectively	3,905	—
Common units, 100,000,000 units authorized; zero and 19,069,662 issued at December 31, 2011 and 2010, respectively	—	516
Additional paid-in capital	1,629,453	—
Accumulated deficit	(616,148)	(615,515)
Accumulated other comprehensive income	3,522	588
Treasury stock, at cost, 649,818 and zero shares at December 31, 2011 and 2010, respectively	(6)	—
Total shareholders' equity/unit holdings equity	1,020,726	(614,411)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	$ 2,551,934	$ 1,691,535

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	December 31, 2011	2010	2009
Revenues and other income:			
Oil and gas revenue	$ 666,912	$ —	$ —
Interest income	9,093	4,231	985
Other income	775	5,109	9,210
Total revenues and other income	676,780	9,340	10,195
Costs and expenses:			
Oil and gas production	83,551	—	—
Exploration expenses, including dry holes	126,409	73,126	22,127
General and administrative	113,579	98,967	55,619
Depletion and depreciation	140,469	2,423	1,911
Amortization—deferred financing costs	16,193	28,827	2,492
Interest expense	65,749	59,582	6,774
Derivatives, net	11,777	28,319	—
Loss on extinguishment of debt	59,643	—	—
Doubtful accounts expense	(39,782)	39,782	—
Other expenses, net	149	1,094	46
Total costs and expenses	577,737	332,120	88,969
Income (loss) before income taxes	99,043	(322,780)	(78,774)
Income tax expense (benefit)	76,686	(77,108)	973
Net income (loss)	22,357	(245,672)	(79,747)
Accretion to redemption value of convertible preferred units	(24,442)	(77,313)	(51,528)
Net loss attributable to common shareholders/unit holders	$ (2,085)	$ (322,985)	$ (131,275)
Net income per share attributable to common shareholders, as restated (Notes 2 and 16):			
Basic (represents the period from May 16, 2011 to December 31, 2011)	$ 0.09		
Diluted (represents the period from May 16, 2011 to December 31, 2011)	$ 0.09		
Weighted average number of shares used to compute net income per share, as restated (Notes 2 and 16):			
Basic (represents the period from May 16, 2011 to December 31, 2011)	368,474		
Diluted (represents the period from May 16, 2011 to December 31, 2011)	368,607		

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY/UNIT HOLDINGS EQUITY

(In thousands)

	Common Units		Common Shares		Additional Paid-in	Accumulated	Accumulated Other Comprehensive	Treasury	
	Units	Amount	Shares	Amount	Capital	Deficit	Income	Stock	Total
Balance as of December 31, 2008	16,172	$ 266	—	$ —	$ 4,134	$ (157,733)	$ —	$ —	$ (153,333)
Issuance of profit units	10	—	—	—	—	—	—	—	—
Relinquishments of profit units	(15)	—	—	—	—	—	—	—	—
Issuance of C1 units	2,500	250	—	—	11,506	—	—	—	11,756
Equity-based compensation	—	—	—	—	3,468	—	—	—	3,468
Net loss	—	—	—	—	—	(79,747)	—	—	(79,747)
Balance as of December 31, 2009	18,667	516	—	—	19,108	(237,480)	—	—	(217,856)
Issuance of profit units	411	—	—	—	—	—	—	—	—
Relinquishments of profit units	(8)	—	—	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	13,791	—	—		13,791
Derivatives, net	—	—	—	—		—	588	—	588
Accrete convertible preferred units to redemption amount	—	—	—	—	(21,143)	(132,363)	—	—	(153,506)
Accrete value of Series C Convertible Preferred Units	—	—	—	—	(11,756)	—	—	—	(11,756)
Net loss	—	—	—	—	—	(245,672)	—	—	(245,672)
Balance as of December 31, 2010	19,070	516	—	—	—	(615,515)	588	—	(614,411)
Issuance of profit units	1,783	—	—	—	—	—	—	—	—
Relinquishments of profit units	(2,686)	—	—	—	—	—	—	—	—
Accrete convertible preferred units to redemption amount	—	—	—	—	(1,452)	(22,990)	—	—	(24,442)
Common and restricted shares issued upon corporate reorganization	(18,167)	(516)	341,177	3,412	1,000,052	—	—	—	1,002,948
Common shares issued at initial public offering, net of offering costs	—	—	34,518	345	580,029	—	—	—	580,374
Equity-based compensation	—	—	—	—	50,966	—	—	—	50,966
Derivatives, net	—	—	—	—	—	—	2,934	—	2,934
Restricted stock awards	—	—	14,836	148	(148)	—	—	—	—
Restricted stock forfeitures	—	—	—	—	6	—	—	(6)	—
Net income	—	—	—	—	—	22,357	—	—	22,357
Balance as of December 31, 2011	—	$ —	390,531	$ 3,905	$1,629,453	$ (616,148)	$ 3,522	$ (6)	$1,020,726

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2011	2010	2009
Operating activities			
Net income (loss)	$ 22,357	$ (245,672)	$ (79,747)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depletion, depreciation and amortization	156,662	31,250	4,403
Deferred income taxes	56,457	(77,614)	99
Unsuccessful well costs	91,254	59,401	74
Derivative related activity	1,811	34,545	—
Equity-based compensation	50,966	13,791	3,468
Doubtful accounts expense	(39,782)	39,782	—
Loss on extinguishment of debt	59,643	—	—
Other	2,953	721	2,287
Changes in assets and liabilities:			
Increase in receivables	(122,859)	(100,605)	(34,531)
(Increase) decrease in inventories	4,176	(12,699)	(14,465)
(Increase) decrease in prepaid expenses and other	(635)	(12,429)	61
Increase in accounts payable	89,214	65,800	80,883
Increase (decrease) in accrued liabilities	(7,308)	11,929	9,877
Net cash provided by (used in) operating activities	364,909	(191,800)	(27,591)
Investing activities			
Oil and gas assets	(478,943)	(444,712)	(411,939)
Other property	(4,303)	(1,452)	(6,376)
Notes receivable	13,653	(61,811)	(52,078)
Restricted cash	84,453	(82,000)	(30,000)
Net cash used in investing activities	(385,140)	(589,975)	(500,393)
Financing activities			
Borrowings under long-term debt	1,503,000	760,000	285,000
Payments on long-term debt	(1,438,000)	—	—
Net proceeds from the initial public offering	580,374	—	—
Net proceeds from issuance of units	—	—	325,344
Deferred financing costs	(52,466)	(17,315)	(90,649)
Net cash provided by financing activities	592,908	742,685	519,695
Net increase (decrease) in cash and cash equivalents	572,677	(39,090)	(8,289)
Cash and cash equivalents at beginning of period	100,415	139,505	147,794
Cash and cash equivalents at end of period	$ 673,092	$ 100,415	$ 139,505
Supplemental cash flow information			
Cash paid for:			
Interest	$ 56,845	$ 52,472	$ 6,765
Income taxes	$ 15,550	$ 762	$ (65)
Non-cash activities:			
Notes receivable applied to FPSO purchase	$ (102,783)	$ —	$ —
Deemed payment and termination of notes receivable	$ —	$ 90,197	$ —

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2011	2010	2009
Net income (loss)	$ 22,357	$ (245,672)	$ (79,747)
Other comprehensive income:			
Change in fair value of cash flow hedges	—	(4,838)	—
Loss on cash flow hedge included in operations	2,934	5,426	—
Income tax benefit	(1,027)	—	—
Other comprehensive income	1,907	588	—
Comprehensive income (loss)	$ 24,264	$ (245,084)	$ (79,747)

See accompanying notes.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements

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 refer 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, major discoveries and exploration prospects offshore Ghana, as well as exploration licenses offshore 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.

Contemporaneous with Kosmos Energy Ltd.'s initial public offering ("IPO"), the Series A Convertible Preferred Units, Series B Convertible Preferred Units and Series C Convertible Preferred Units (collectively the "Convertible Preferred Units") and common units of Kosmos Energy Holdings were exchanged into common shares of Kosmos Energy Ltd. based on the pre-offering equity value of such interests in our corporate reorganization (the "corporate reorganization"). This resulted in the Convertible Preferred Units and the common units being exchanged into 277.7 million and 63.5 million common shares of Kosmos Energy Ltd., respectively, or 341.2 million common shares in the aggregate. The 341.2 million common shares included 10.0 million restricted shares issued to management and employees in exchange for unvested profit units in connection with our corporate reorganization. The common shares have one vote per share and a par value of $0.01. As a result of this corporate reorganization, Kosmos Energy Holdings became wholly owned by Kosmos Energy Ltd.

Kosmos Energy Ltd. completed its IPO of 33.0 million common shares on May 16, 2011. In June 2011, the Company closed the sale of an additional 1.5 million common shares pursuant to the over-allotment option exercised by the underwriters of the IPO. This partial exercise of the over-allotment option brings the total number of common shares sold in the offering to 34.5 million. Our net proceeds from the sale of 34.5 million common shares, after underwriting discounts and commissions and offering expenses, were $580.4 million.

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

2. Accounting Policies

Restatement

Subsequent to the issuance of the Company's fiscal 2011 consolidated financial statements, management identified an error in the presentation and disclosure of basic and diluted net income per share attributable to common shareholders and the weighted average number of shares used to compute net income per share attributable to common shareholders for the year ended December 31, 2011 as presented on the Company's consolidated statements of operations and Note 16-Net Income Per Share (Restated).

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

We did not present net income per share attributable to common shareholders for the period from the date of our Corporate Reorganization to December 31, 2011 on the consolidated statements of operations. Rather, we presented pro forma net income per share attributable to common shareholders on the statements of operations for the year ended December 31, 2011 and in the footnotes to the consolidated financial statements. We have restated the accompanying statement of operations for the year ended December 31, 2011 to remove the presentation of pro forma net income per share attributable to common shareholders and to present net income per share attributable to common shareholders from the date of our Corporate Reorganization on May 16, 2011 to December 31, 2011. For additional information, please refer to Note 16-Net Income Per Share (Restated).

For the period from May 16, 2011 to December 31, 2011, the basic and diluted net income per share attributable to common shareholders of $0.09 on our consolidated statements of operations is greater than our original presentation of pro forma basic and diluted net income per share attributable to common shareholders of $0.06 even though our total earnings for the year ended December 31, 2011 have not changed.

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

As of December 31, 2011, we had $23.7 million of current restricted cash related to funds that will be utilized for payment on interest and commitment fees on our commercial debt facility. 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. The $3.8 million long-term restricted cash is related to cash collateralization for performance guarantees related to our petroleum agreements.

As of December 31, 2010, in accordance with our commercial debt facilities that existed as of December 31, 2010, we had restricted cash of $89.0 million, of which $80.0 million was included in current assets. Additionally, effective December 30, 2010, we provided a $23.0 million cash collateralized irrevocable standby letter of credit ("Letter of Credit") with respect to our share of Tullow Ghana Limited's, a subsidiary of Tullow Oil plc, ("Tullow") Letter of Credit related to Tullow's drilling contract for the "Eirik Raude" semi-submersible rig. In March 2011, the restricted cash related

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

to the commercial debt facilities agreement and the cash collateral for the Letter of Credit was released as a result of our debt refinancing. The Letter of Credit was collateralized by our available borrowing capacity under the commercial debt facility until it expired on September 14, 2011.

Receivables

The Company's receivables consist of joint interest billings, oil sales, notes 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. The Company's allowances for doubtful accounts totaled zero and $39.8 million as of December 31, 2011 and 2010, respectively. See Note 5—Joint Interest Billings.

Inventories

Inventories consisted of $26.9 million and $25.2 million of materials and supplies and $0.2 million and $12.5 million of hydrocarbons as of December 31, 2011 and 2010, 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. 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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

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.

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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

Our wholly owned subsidiaries, Kosmos Energy Finance and Kosmos Energy Finance International, meet the definition of a VIE and the Company, which is the ultimate parent of both subsidiaries. The Company absorbs all of the variability from the VIEs and, therefore, is the primary beneficiary. Kosmos Energy Finance and Kosmos Energy Finance International are consolidated in these financial statements.

As of December 31, 2011 and 2010, Kosmos Energy Finance had zero and $58.0 million, respectively, in cash and cash equivalents. Kosmos Energy Finance did not have any assets or liabilities as of December 31, 2011, and will have no financial statement activity in the future. As of December 31, 2010, Kosmos Energy Finance's other assets and liabilities are shown separately on the face of the consolidated balance sheet in the following line items: current and long-term restricted cash; deferred financing costs; long-term derivatives asset; current and long-term debt; and current and long-term derivatives liabilities.

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 December 31, 2011, in the following line items: current restricted cash; deferred financing costs; long-term debt; and current and long-term derivatives liabilities. At December 31, 2011, Kosmos Energy Finance International had $231.6 million in cash and cash equivalents, $0.1 million in other receivables, $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 deferred premium puts and compound options (calls on puts). We also use interest rate swap contracts to mitigate our exposure to interest rate fluctuations related to our commercial debt facilities. 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 and accordingly the changes in the fair value of the instruments are recognized in earnings in the period of change. See Note 10—Derivative Financial Instruments.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

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 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 (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards with a combination of market and service vesting criteria.

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.

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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

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. Additionally, 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.

Recent Accounting Standards

In May 2011, the FASB issued ASU No. 2011-04, "Amendments to Achieve Common Fair Value Measurement and DisclosureRequirements in U.S. GAAP and IFRSs," to develop common requirements for valuation and disclosure of fair value measurements in accordance with U.S. GAAP and International Financial Reporting Standards. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. We do not expect the adoption of this ASU will have amaterial effect on our consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income," to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. In December 2011, the FASB issued ASU No. 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." ASU No. 2011-12 defers certain reporting requirements ASU No. 2011-05. We do not expect the adoption of ASU 2011-05 and ASU 2011-12 will have a material effect on our consolidated financial statements.

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 affects 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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

3. Acquisition of FPSO and Notes Receivable

On December 29, 2011, Tullow as Unit Operator for and on behalf of the Jubilee Unit partners under the Unitization and Unit Operating Agreement ("Jubilee UUOA"), acquired the FPSO we are using to produce hydrocarbons from the Jubilee Field from MODEC, Inc. ("MODEC") for $754.5 million, or $202.6 million net to Kosmos. At the time of the acquisition of the FPSO, the 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. The acquisition was recorded as an increase to oil and gas property. The Jubilee Unit operator will become the operator of the FPSO. 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.

Effective May 7, 2010, Tullow, as Unit Operator for and on behalf of the Jubilee Unit, entered into an Advance Payments Agreement with 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. As of December 31, 2011 and 2010, the remaining balance under the Advance Payments Agreement was zero and $113.9 million, respectively. We recognized interest income of $5.7 million, $1.0 million and $0.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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. TGL is the Unit Operator, and Kosmos is the Technical Operator for the development of the Jubilee Field. The accounting for the Jubilee Unit included in these consolidated financial statements is in accordance with the tract participation stated in the Jubilee UUOA. Pursuant to the terms of the Jubilee UUOA, the tract participations are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. 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 as of December 31, 2011, 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. Our capital costs due related to our increased Unit Interest is expected to be paid within one year. Although the Jubilee Field is unitized, Kosmos' working interest in each block outside the boundary of

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

4. Jubilee Field Unitization (Continued)

the Jubilee Unit area was not changed. Kosmos remains operator of the WCTP Block outside the Jubilee Unit area. See Note 19—Subsequent Events.

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 December 31, 2011 and 2010, we had$199.7 million and $124.4 million, respectively, included in current joint interest billings receivable and zero and $21.9 million, respectively, included in long-term joint interest billings receivable. Long-term balances are shown net of allowances of zero and $39.8 million as of December 31, 2011 and 2010, respectively.

In August 2009, Ghana National Petroleum Corporation ("GNPC") notified our unit partners and us that it would exercise its right for the applicable contractor group to pay its 2.5% WCTP Block share and 5.0% DT Block share of the Jubilee Field development costs and be reimbursed for such costs plus interest out of a portion of GNPC's production revenues under the terms of the WCTP PA and DT PA, respectively. As of December 31, 2011 and 2010, the joint interest billing receivables due from GNPC was $11.1 million and $29.6 million, respectively.

EO Group's share of costs under the WCTP PA until first production occurred were paid by Kosmos. 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 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:

	December 31,	
	2011	2010
	(In thousands)	
Oil and gas properties, net:		
Proved properties	$ 607,338	$ 426,831
Unproved properties	294,701	198,149
Support equipment and facilities	600,848	371,319
Less: accumulated depletion	(135,622)	(6,430)
	$ 1,367,265	$ 989,869

We recorded depletion expense of $135.5 million, zero and zero for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had depletion costs of nil and $6.4 million included in crude oil inventory as of December 31, 2011 and 2010, respectively.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

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 years ended December 31, 2011, 2010 and 2009. The table excludes $51.4 million, $56.0 million and nil in costs that were capitalized and subsequently expensed in 2011, 2010 and 2009, respectively.

	Years Ended December 31,		
	2011	2010	2009
	(In thousands)		
Beginning balance	$ 167,511	$ 114,307	$ 71,883
Additions to capitalized exploratory well costs pending the determination of proved reserves	139,949	55,706	508,197
Reclassification due to determination of proved reserves	—	—	(465,773)
Capitalized exploratory well costs charged to expense	(39,868)	(2,502)	—
Ending balance	$ 267,592	$ 167,511	$ 114,307

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

	Years Ended December 31,		
	2011	2010	2009
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$ 132,838	$ 49,022	$ 91,909
Exploratory well costs capitalized for a period one to three years	134,754	118,489	22,398
Ending balance	$ 267,592	$ 167,511	$ 114,307
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3	1

As of December 31, 2011, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Mahogany East Area in the WCTP Block and the Tweneboa and Enyenra discoveries in the DT Block.

Odum Discovery—Due to the technical challenges presented by the gravity of the oil encountered in the Odum discovery, we determined that a declaration of commerciality was not warranted during the second quarter of 2011. Accordingly, the related suspended well costs associated with the Odum discovery of $32.6 million were written off.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

7. Suspended Well Costs (Continued)

Mahogany East Area—The Mahogany East 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, 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 PAcontains 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 East 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 are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

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 declaration, a PoD would be prepared and submitted to Ghana's Ministry of Energy. However, the DT Block partners have the option to request a new petroleum agreement for the Discovery Area, thereby extending the period of commercial assessment for the Tweneboa discovery.

Enyenra Discovery—Two appraisal wells have been drilled. Following additional appraisal, drilling and evaluation, a decision regarding commerciality of the Enyenra discovery is expected to be made by the DT Block partners in the third quarter of 2012. Within six months of such declaration, a PoD would be prepared and submitted to Ghana's Ministry of Energy.

8. Accounts Payable and Accrued Liabilities

At December 31, 2011 and 2010, $278.0 million and $163.5 million, respectively, were recorded for invoices received but not paid. Accrued liabilities were $37.2 million and $53.2 million at December 31, 2011 and 2010, respectively, and consisted of the following:

	December 31,	
	2011	2010
	(In thousands)	
Accrued liabilities:		
Accrued exploration, development and production	$ 27,666	$ 26,843
Accrued general and administrative expenses	2,159	23,393
Accrued interest	1,208	655
Taxes other than income	1,095	1,936
Income taxes	5,066	381
	$ 37,194	$ 53,208

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. See Note 19—Subsequent Events.

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 December 31, 2011, borrowings under the Facility totaled $1.1 billion. As of December 31, 2011, the undrawn availability under the Facility was an additional $153.0 million. Interest expense was $45.2 million, $39.0 million and $2.0 million (net of capitalized interest of $4.2 million, $9.8 million and $0.6 million) and commitment fees were $8.0 million, $8.2 million and $4.8 million for the years ended December 31, 2011, 2010 and 2009, 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 $3.0 million of additional interest expense during the year ended December 31, 2011.

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 required repayments under the Facility begin). Beginning on 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, is 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. The formula to calculate the borrowing base amount is based, in part, on the sum of the net present value of net cash flows and relevant capital expenditures reduced by certain percentages.

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Notes to Consolidated Financial Statements (Continued)

9. Debt (Continued)

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 December 15, 2011 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,

in each case, as calculated on the basis of all available information. 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.

At December 31, 2011, the scheduled maturities of debt during the five year period and thereafter are as follows:

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

(1) The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2011. Any increases ordecreases 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

The Company uses 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.

The Company applies the provisions of ASC 815—Derivatives and Hedging, which require each derivative instrument to be recorded on 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. The Company does not apply hedge accounting treatment to its oil derivative contracts and, therefore, the change in the fair value of these instruments is recognized in earnings in the period of change. These fair value changes are shown in our statement of operations.

Effective June 1, 2010, the Company discontinued hedge accounting on all interest rate derivative instruments. Therefore, the Company recognizes, from that date forward, changes in the fair value of the instruments in earnings during the period of change. The effective portions of the discontinued

10. Derivative Financial Instruments (Continued)

hedges as of May 31, 2010, are included in accumulated other comprehensive income or loss ("AOCI(L)") in the equity section of the accompanying consolidated balance sheets, and are being transferred to earnings when the hedged transaction is recognized in earnings.

Oil Derivative Contracts

In 2010, we entered into various oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production. These contracts consist of deferred premium puts and compound options (calls on puts).

The Company manages market and counterparty credit risk in accordance with policies and guidelines approved by the Board. In accordance with these policies and guidelines, the Company's 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 December 31, 2011:

Type of Contract and Period	bbl/day	Weighted Average Floor Price	Weighted Average Deferred Premium/bbl
Deferred Premium Puts			
January 2012—December 2012	4,625	$ 62.74	$ 7.04
January 2013—December 2013	2,515	61.73	7.32
Compound Options (calls on puts)			
July 2012—December 2012(1)	5,399	66.48	6.73
January 2013—June 2013(1)	3,855	66.48	7.10

(1) The calls expire June 29, 2012, and have a weighted average premium of $4.82/bbl.

Interest Rate Swaps Derivative Contracts

In 2010, Kosmos entered into derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation, whereby it converts the interest due on certain floating rate debt to a weighted average fixed rate. The following table summarizes our open interest rate swaps as of December 31, 2011:

Termination Date	Notional Amount (In thousands)	Fixed Rate	Floating Rate
June 2014	$ 77,500	0.98%	6-month LIBOR
June 2015	75,007	1.34%	6-month LIBOR
June 2016	161,250	2.22%	6-month LIBOR
June 2016	161,250	2.31%	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

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

10. Derivative Financial Instruments (Continued)

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 December 31, 2011 and 2010:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2011	2010
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative asset:			
Commodity	Derivatives assets—current	$ —	$ —
Interest rate	Derivatives assets—current	—	—
Commodity	Derivatives assets—noncurrent	—	—
Interest rate	Derivatives assets—noncurrent	—	1,501
Derivative liability:			
Commodity	Derivatives liabilities—current	(20,303)	(13,979)
Interest rate	Derivatives liabilities—current	(4,104)	(6,375)
Commodity	Derivatives liabilities—long-term	(4,457)	(14,340)
Interest rate	Derivatives liabilities—long-term	(3,970)	(764)
Total derivatives not designated as hedging instruments		$ (32,834)	$ (33,957)

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31, 2011	2010	2009
		(In thousands)		
Derivatives in cash flow hedging relationships:				
Interest rate	AOCI(L)	$ —	$ 588	$ —
Interest rate(1)	Interest expense	(2,934)	(5,426)	—
Total derivatives in cash flow hedging relationships		$ (2,934)	$ (4,838)	$ —
Derivatives not designated as hedging instruments:				
Commodity	Derivatives, net	$ (11,777)	$ (28,319)	$ —
Interest rate	Interest expense	(9,548)	(6,967)	—
Total derivatives not designated as hedging instruments		$ (21,325)	$ (35,286)	$ —

(1) Amounts were reclassified from AOCI(L) into earnings.

The fair value of the effective portion of the derivative contracts on May 31, 2010, is reflected in AOCI(L) 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 $0.2 million of losses from AOCI(L) to interest expense within the

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10. Derivative Financial Instruments (Continued)

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 December 31, 2011 and 2010, for each fair value hierarchy level:

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In thousands)			
December 31, 2011				
Assets:				
Money market accounts	$ 462,214	$ —	$ —	$ 462,214
Interest rate derivatives	—	—	—	—
Liabilities:				
Commodity derivatives	—	(24,760)	—	(24,760)
Interest rate derivatives	—	(8,074)	—	(8,074)
Total	$ 462,214	$ (32,834)	$ —	$ 429,380
December 31, 2010				
Assets:				
Money market accounts	$ 18,056	$ —	$ —	$ 18,056
Interest rate derivatives	—	1,501	—	1,501
Liabilities:				
Commodity derivatives	—	(28,319)	—	(28,319)

Interest rate derivatives	—	(7,139)	—	(7,139)
Total	$ 18,056	$ (33,957)	$ —	$ (15,901)

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Notes to Consolidated Financial Statements (Continued)

11. Fair Value Measurements (Continued)

All fair values have been adjusted for nonperformance risk resulting in a decrease of the commodity derivative liabilities of approximately $0.8 million and a decrease of the interest rate derivatives of approximately of $0.3 million as of December 31, 2011. When the accumulated net present value for all of the derivative contracts with a counterparty is in an asset position, the Company uses the 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, joint interest billings, oil sales, notes 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 the Company for those periods. The Company's long-term receivables after any allowances for doubtful accounts approximate fair value.

Commodity Derivatives

The Company's commodity derivatives represent crude oil deferred premium puts and compound options for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to the Company's 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 December 31, 2011 and 2010 the Company had interest rate swaps with notional amounts of $475.0 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. See Note 10—Derivative Financial Instruments for additional information regarding the Company's derivative instruments.

12. Asset Retirement Obligations

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

	December 31, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$ 16,752	$ —
Liabilities incurred during period	1,702	16,570
Revisions in estimated retirement obligations	—	—
Liabilities settled during period	—	—
Accretion expense	2,216	182
Ending asset retirement obligations	$ 20,670	$ 16,752

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

12. Asset Retirement Obligations (Continued)

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

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 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.

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Notes to Consolidated Financial Statements (Continued)

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 ranging from $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 anniversaries 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	Weighted-Average Grant-Date Fair Value
	(In thousands)	
Outstanding at December 31, 2009	13,507	$ 0.81
Granted	411	5.27
Relinquished	(8)	2.45
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	Weighted-Average Grant-Date Fair Value
	(In thousands)	
Outstanding at December 31, 2009	6,957	$ 1.06
Granted	411	5.27
Vested	(2,719)	1.03
Relinquished	(8)	2.45
Accelerated vesting	(1,177)	10.66
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

Effective December 31, 2010, James C. Musselman retired as the Company's Chairman and Chief Executive Officer. The Company entered into a retirement agreement with Mr. Musselman on December 17, 2010. Pursuant to the retirement agreement, 1.2 million profit units of Kosmos Energy

14. Equity-based Compensation (Continued)

Holdings that were unvested as of his retirement date became fully vested as of such date, resulting in unit-based compensation of $11.5 million in the fourth quarter of 2010.

Total profit unit compensation expense recognized in income was $1.2 million, $13.8 million and $3.5 million for the year ended December 31, 2011, 2010 and2009, respectively.

The significant assumptions used to calculate the fair values of the profit units granted over the past three years, 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

As part of the 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 the 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 December 31, 2011:

	Shares (In thousands)
Approved and authorized awards(1)	24,503
Awards issued after May 16, 2011(1)	(14,836)
Awards forfeited(1)	98
Awards available for future grant	9,765

(1) Excludes 10.0 million restricted stock awards that were exchanged for unvested profit units and any related forfeitures of such awards.

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 $49.8 million in compensation expense

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

14. Equity-based Compensation (Continued)

from our restricted stock awards during the year ended December 31, 2011. The following table reflects the outstanding restricted stock awards as of December 31, 2011:

	Restricted Shares	Weighted-Average Grant-Date Fair Value
	(In thousands)	
Outstanding at May 16, 2011	—	$ —
Exchanged	10,033	2.79
Granted	14,836	16.96
Forfeited	(650)	3.21
Vested	(3,501)	0.36
Outstanding at December 31, 2011	20,718	13.33

During 2011, the Company granted restricted stock awards with service vesting criteria and awards with a combination of market and service vesting criteria under the LTIP. 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 (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards with a combination of market and service vesting criteria.

For awards with a combination of market and service vesting criteria, the number of shares 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. 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 0.6% to 1.1%.

15. Income Taxes

Kosmos Energy Ltd. is a Bermuda company that is not subject to taxation at the corporate level. Kosmos Energy Ltd.'s operating subsidiaries in the United States, Ghana, Cameroon, Morocco and Suriname are subject to taxation in their respective jurisdictions.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

15. Income Taxes (Continued)

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

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Bermuda	$ (4,826)	$ —	$ —
United States	8,808	1,476	2,497
Foreign—other	95,061	(324,256)	(81,271)
Income (loss) before income taxes	$ 99,043	$ (322,780)	$ (78,774)

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

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Current:			
Bermuda	$ —	$ —	$ —
United States	20,229	506	874
Foreign—other	—	—	—
Total current	20,229	506	874
Deferred:			
Bermuda	—	—	—
United States	(16,857)	(143)	99
Foreign—other	73,314	(77,471)	—
Total deferred	56,457	(77,614)	99
Income tax expense (benefit)	$ 76,686	$ (77,108)	$ 973

The following table reconciles the differences between our applicable statutory tax rate and our effective income tax rate:

	Years Ended December 31, 2011	2010	2009
Tax provision at statutory rate (Bermuda)	—%	—%	—%
Income/loss subject to tax in excess of statutory rate	53.4	23.2	18.2
Change in valuation allowance	19.6	1.1	(19.2)
Other	4.4	(0.4)	(0.2)
Consolidated effective tax rate	77.4%	23.9%	(1.2)%

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Notes to Consolidated Financial Statements (Continued)

15. Income Taxes (Continued)

Deferred taxes reflect the tax effects of differences between the amounts recorded as assets and liabilities for financial reporting purposes and the amounts recorded for income tax purposes. The tax effects of significant temporary differences giving rise to deferred tax assets and liabilities are as follows:

	December 31. 2011	December 31. 2010
	(In thousands)	
Deferred tax assets:		
Ghana foreign capitalized operating expenses	$ 6,355	$ 8,473
Foreign net operating losses	92,154	134,090
Equity compensation	17,282	—
Unrealized derivative losses	7,622	—
Other	7,354	6,007
Total deferred tax assets	130,767	148,570
Valuation allowance	(49,502)	(30,140)
Total deferred tax assets, net	81,265	118,430
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(60,635)	(41,143)
Other	—	(200)
Total deferred tax liabilities	(60,635)	(41,343)
Net deferred tax asset	$ 20,630	$ 77,087

The Company had net deferred tax assets in Ghana totaling approximately $20.6 million at December 31, 2009 primarily relating to capitalized operating expenses incurred during the development phase of the Jubilee Field. Prior to the commencement of production from the Jubilee Field on November 28, 2010, the Company maintained a full valuation allowance against its net deferred tax asset. However, at December 31, 2010, the Company determined that it was more likely than not that the deferred tax asset for its Ghana operations would be recognized, resulting in the valuation allowance no longer being necessary. Therefore, we released the $20.6 million deferred tax asset valuation allowance and recognized $56.9 million of deferred tax assets generated during 2010. The factors that the Company considered are discussed below. Based on these factors, the Company concluded that many of the considerations that previously led to the need for a valuation allowance related to the Ghana deferred tax assets no longer existed as of December 31, 2010.

In determining that a valuation allowance was not needed for the Ghanaian deferred tax assets at December 31, 2010 we considered the requirements of ASC 740, including that all evidence, both positive and negative, should be considered to determine whether, based on all the weight of the available evidence, it is more-likely-than-not a deferred tax asset will or will not be realized. If it is more-likely-than-not that the deferred tax asset will be realized, a valuation allowance is not needed. In performing this assessment for the Ghanaian deferred tax assets, the Company determined that the factors that led to the creation of deferred tax assets while operating as a development stage entity

15. Income Taxes (Continued)

changed significantly when the Company moved into the production phase. We considered the following evidence in assessing the realizability of the net deferred tax asset as of December 31, 2010:

- The commencement of oil production on November 28, 2010. Equipment and infrastructure was fully in place in the fourth quarter of 2010 immediately prior to production commencing, and the November 28, 2010 successful commencement of production confirmed our expectations that these assets could be utilized to successfully produce from the field with an economical cost structure.

- The recognition of our first revenues from oil production in January 2011. The Company was a development stage entity as of December 31, 2010, but upon recognition of our first revenues in January 2011, was no longer categorized as such.

- The existence of significant proved reserves that had been independently verified.

- The Company was producing a commodity (crude oil) with observable market demand capable of purchasing all barrels produced. Prices for oil could be estimated through forward pricing curves.

- The ability to recover our deferred tax assets based on our projections of at such time taxable income for future years. Production volumes utilized in our projections were based on our proved reserve estimates as of December 31, 2010, which had been independently verified, and our schedule for production which was approved by the Jubilee Unit partners, and forecasted increased production during 2011 and future periods. Prices were estimated based on prices utilized to calculate our standardized measure as of December 31, 2010. We estimated our expenses based on current contracts and cost structures in place at that time. Based on the production plan and a price per barrel of $79.35, which is also used to calculate our standardized measure as of December 31, 2010, we anticipated realization of the net operating loss carryforward by the end of 2012.

- The excess of appreciated asset value over the tax basis of our Ghanaian net assets of an amount sufficient to realize the deferred tax asset. Our estimates of the excess of the appreciated asset value were based upon the independently verified reserve report, third party offers for our Ghana assets, and other market indicators.

- We tested the sensitivity of our projection of taxable income to changes in production volumes and prices, which indicated that future taxable income was sufficient to recover the deferred tax assets under various scenarios.

- There is an unlimited net operating loss carryforward period under Ghanaian tax law, which provides flexibility in utilization of the net operating loss.

ASC 740 provides a more-likely-than-not standard in evaluating whether a valuation allowance is necessary after weighing all of the available evidence. Using the more-likely-than-not standard and weighing all available positive and negative evidence, the Company believed that, as of December 31, 2010, considering the facts and circumstances at that time, the negative evidence of the cumulative losses incurred during the development stage was overcome by the positive evidence relating to the Company's ability to more-likely-than-not realize the deferred tax assets in Ghana. Accordingly, we determined that it is more likely than not that the deferred tax asset for our Ghanaian operations would be realized.

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Notes to Consolidated Financial Statements (Continued)

15. Income Taxes (Continued)

As of December 31, 2011, our Ghana operations has a net deferred tax asset of approximately $4.2 million. In consideration of the realizability of our net deferred tax asset as of December 31, 2011, we considered the following, in addition to the aforementioned positive evidence:

- Our operations subject to taxation in Ghana is no longer in a three year cumulative loss position.
- For the year ended December 31, 2011, we expect to utilize approximately $164.0 million of our net operatingloss carryforward.
- The ability to recover our deferred tax assets based on our projections of taxable income for future years. Production volumes utilized in our projection were based on our proved reserve estimates as of December 31, 2011, which have been independently verified, and our schedule for production which was approved by the Jubilee Unit partners, and forecasted for increased production during 2012 and future periods. Prices were estimated based on prices utilized to calculate our standardized measure as of December 31, 2011. We estimated our expenses based on current contracts and cost structures in place at that time. Based on such projections, we estimate that we will utilize the remainder of the net operating loss during 2012.

Based on our analysis, we concluded that it is more-likely-than-not that our remaining Ghana deferred tax asset as of December 31, 2011 will be realized in the future.

The Company has recorded a full valuation allowance against the net deferred tax assets in Cameroon and Morocco. The net change in the valuation allowance of $19.4 million is due to the additional losses generated in Morocco and Cameroon.

The Company has entered into various petroleum agreements in Morocco. These agreements provide for a tax holiday, at a 0% tax rate, for a period of 10 years beginning on the date of first production. The Company currently has recorded deferred tax assets of $10.9 million, recorded at the Moroccan statutory rate of 30%, with an offsetting valuation allowance of $10.9 million. We will re-evaluate our deferred tax position upon entering the tax holiday period and at such time may reduce the statutory rate applied to the deferred tax assets in Morocco to the extent those deferred tax assets are realized within the tax holiday period.

The Company has foreign net operating loss carryforwards of approximately $89.6 million which begin to expire in 2011 through 2015 and approximately $137.4 million which do not expire.

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 the Company operates. The Company is open to U.S. federal income tax examinations for tax years 2008 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 years 2004 through 2011 in its significant other foreign jurisdictions (Ghana, Cameroon and Morocco).

As of December 31, 2011, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense, but has had no need to accrue any to date.

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Notes to Consolidated Financial Statements (Continued)

16. Net Income Per Share (Restated)

In the periods prior to our Corporate Reorganization, we do not calculate net income per share attributable to common shareholders because we did not have common stock outstanding, as defined in accounting literature, in those periods. For the year ended December 31, 2011, we have presented net income per share attributable to common shareholders from the date of our Corporate Reorganization, May 16, 2011 to December 31, 2011.

Subsequent to our Corporate Reorganization, we have outstanding participating securities in the form of service vesting restricted stock awards granted to employees and directors (Note 14). In the calculation of basic net income per share attributable to common shareholders, these 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 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 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 per share attributable to common shareholders is computed as (i) net income 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 per share attributable to common shareholders is computed as (i) basic net income attributable to common shareholders, (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding.

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Notes to Consolidated Financial Statements (Continued)

16. Net Income Per Share (Continued)

(In thousands, except per share data)		May 16, 2011 - December 31, 2011
Net loss for the year ended December 31, 2011	$	(2,085)
Net loss attributable to the period from January 1, 2011 to May 15, 2011		(38,191)
Net income attributable to common shareholders	$	36,106
Numerator:		
Net income attributable to common shareholders	$	36,106
Less: Basic income allocable to participating securities(1)		1,643
Basic net income allocable to common shareholders		34,463
Diluted adjustments to income allocable to participating securities(1)		9
Diluted net income allocable to common shareholders	$	34,472
Denominator:		
Weighted average number of shares used to compute net income per share:		
Basic		368,474
Restricted stock awards(1)(2)		133
Diluted		368,607
Net income per share attributable to common shareholders:		
Basic	$	0.09
Diluted	$	0.09

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

(2) For the period from May 16, 2011 through December 31, 2011, we excluded 20.5 million outstanding restricted stock awards from the computations of diluted net income per share because the effect would have been anti-dilutive.

17. 401(k) Plan

The Company offers a 401(k) Plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. Employee contributions of up to 6% of compensation, as defined by the plan, is matched by the Company at 100%. The Company's match is vested immediately. Matching contributions made by the Company to the 401(k) Plan were approximately $1.2 million, $0.7 million and $0.6 million for the years ended December 31, 2011, 2010 and 2009, respectively. Effective January 1, 2012, employee contributions of up to 8% of compensation, as defined by the plan, will be matched by the Company at 100%.

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Notes to Consolidated Financial Statements (Continued)

18. Commitments and Contingencies

On June 23, 2008, Kosmos signed an offshore drilling contract with Alpha Offshore Drilling Services Company, a wholly owned subsidiary of Atwood Oceanics, Inc., for the semi-submersible drilling rig "Atwood Hunter." Noble Energy EG Ltd. ("Noble") also is a party to the contract. The initial daily rig rate is subject to annual adjustments for cost increases.

In addition, the Company leases other facilities under various operating leases that expire through 2019, including our office space. Rent expense under these agreements, was $2.3 million, $1.4 million and $1.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Future minimum rental commitments under these leases at December 31, 2011, are as follows:

	Payments Due By Year(2)						
	Total	2012	2013	2014	2015	2016	Thereafter
	(In thousands)						
Drilling rig contract(1)	$ 137,168	$ 137,168	$ —	$ —	$ —	$ —	$ —
Operating leases	21,797	234	2,821	2,921	3,022	3,122	9,677

(1) Does not include any well commitments we may have under our oil and natural gas licenses.

(2) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes $19.1 million of commitments for exploration activities in our petroleum contracts.

19. Subsequent Events

Amendment to our commercial debt facility

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 at $2.0 billion.

Acquisition of Sabre Oil & Gas Holdings Limited's interest in DT Block

One of our DT Block partners, Sabre, provided notice that it intends to transfer all of its 4.05% participating interest in the DT Block to a third party for approximately $365.0 million, with up to $45.0 million in contingent payments upon achieving certain performance milestones. Under the DT PA, the block partners have a right of first refusal for the transfer of such interest to a third party, assuming the block partner is willing to match the terms and conditions of the existing offer of the third party. On February 23, 2012, we exercised our right to accept the terms and conditions of the proposed transfer. Subject to Government of Ghana consent, we anticipate the transaction to close during the second quarter of 2012. After the acquisition, our interest in the DT Block and Jubilee Unit will increase to 22.05% and 25.82258%, respectively.

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Supplemental Oil and Gas Data (Unaudited)

Net proved oil and gas reserve estimates presented were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers located in Dallas, Texas, adjusted for imbalances. NSAI have prepared the reserve estimates presented herein and meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to independent reserve engineers for their reserves estimation process.

Net Proved Developed and Undeveloped Reserves

The following table is a summary of net proved developed and undeveloped oil and gas reserves to Kosmos' interest in the Jubilee Field in Ghana.

	Oil (Mmbbl)	Gas (Bcf)	Total (Mmboe)
Net proved undeveloped reserves at December 31, 2009	52	—	52
Discoveries and extensions	—	22	4
Production	—	—	—
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2010	52	22	56
Discoveries and extensions	—	—	—
Production	(6)	(2)	(6)
Revision in estimate(1)	1	4	1
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2011(2)	47	24	51
Proved developed reserves(2)			
December 31, 2009	—	—	—
December 31, 2010	35	18	38
December 31, 2011	23	16	26
Proved undeveloped reserves(2)			
December 31, 2009	52	—	52
December 31, 2010	17	4	18
December 31, 2011	25	8	26

(1) The increase in estimated oil reserves is due to an increase in our Jubilee Field unit interest (see Note 4—Jubilee Field Unitization). The estimated increase in gas reserves represents our increased Jubilee Field unit interest and an increase in estimated gas reserves to be utilized as fuel gas for the FPSO.

(2) The sum of proved developed reserves and proved undeveloped reserves may not add to net proved developed and undeveloped reserves due to rounding.

Net proved reserves were calculated utilizing the twelve month unweighted arithmetic average of the first-day-of-the-month oil price for each month for Brent crude in the period January through December 2011. The average Brent crude price of $111.02 per barrel is adjusted for crude handling,

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Supplemental Oil and Gas Data (Unaudited)

transportation fees, quality, and a regional price differential. Based on the crude quality, these adjustments are estimated to be an additional $0.02 per barrel; therefore, the oil flowstreams receive a crude price of $111.04 per barrel. This oil price is held constant throughout the lives of the properties. There is no gas price used because gas reserves are consumed in operations as fuel.

Proved oil and gas reserves are defined by the SEC Rule 4.10(a) of Regulation S-X as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recovered under current economic conditions, operating methods, and government regulations. Inherent uncertainties exist in estimating proved reserve quantities, projecting future production rates and timing of development expenditures.

Capitalized Costs Related to Oil and Gas Activities

The following table presents aggregate capitalized costs related to oil and gas activities:

	Ghana	Other(1)	Total
		(In thousands)	
As of December 31, 2011			
Unproved properties	$ 290,736	$ 3,966	$ 294,702
Proved properties	1,208,185	—	1,208,185
	1,498,921	3,966	1,502,887
Accumulated depletion, depreciation and amortization	(135,622)	—	(135,622)
Net capitalized costs	$ 1,363,299	$ 3,966	$ 1,367,265
As of December 31, 2010			
Unproved properties	$ 190,184	$ 7,965	$ 198,149
Proved properties	798,150	—	798,150
	988,334	7,965	996,299
Accumulated depletion, depreciation and amortization	(6,430)	—	(6,430)
Net capitalized costs	$ 981,904	$ 7,965	$ 989,869

(1) Includes Africa and South America.

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Supplemental Oil and Gas Data (Unaudited)

Costs Incurred in Oil and Gas Activities

The following table reflects total costs incurred, both capitalized and expensed, for oil and gas property acquisition, exploration, and development activities for the year.

	Ghana	Other(1)	Total
		(In thousands)	
Year ended December 31, 2011			
Property acquisition:			
Unproved	$ —	$ 1,932	$ 1,932
Proved	—	—	—
Exploration	187,272	33,758	221,030
Development	410,035	—	410,035
Total costs incurred	$ 597,307	$ 35,690	$ 632,997
Year ended December 31, 2010			
Property acquisition:			
Unproved	$ —	$ —	$ —
Proved	—	—	—
Exploration	109,624	32,304	141,928
Development	325,975	—	325,975
Total costs incurred	$ 435,599	$ 32,304	$ 467,903
Year ended December 31, 2009			
Property acquisition:			
Unproved	$ —	$ —	$ —
Proved	—	—	—
Exploration	88,103	20,776	108,879
Development	304,948	—	304,948
Total costs incurred	$ 393,051	$ 20,776	$ 413,827

(1) Includes Africa and South America.

Standardized Measure for Discounted Future Net Cash Flows

The following table provides projected future net cash flows based on the twelve month unweighted arithmetic average of the first-day-of-the-month oil price for Brent crude in the period January through December 2011. The average Brent crude price of $111.02 per barrel is adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the crude quality, these adjustments are estimated to be an additional $0.02 per barrel; therefore, the oil flowstreams receive a crude price of $111.04 per barrel. Because prices used in the calculation are average prices for that year, the standardized measure could vary significantly from year to year based on market conditions that occurred.

The projection should not be interpreted as representing the current value to Kosmos. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. Kosmos' investment and operating decisions are not based

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Supplemental Oil and Gas Data (Unaudited)

on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on a wide range of different price and cost assumptions.

The standardized measure is intended to provide a better means to compare the value of Kosmos' proved reserves at a given time with those of other oil producing companies than is provided by comparing raw proved reserve quantities.

	Ghana (In millions)
At December 31, 2011	
Future cash inflows	$ 5,230
Future production costs	(655)
Future development costs	(698)
Future Ghanaian tax expenses(1)	(1,027)
Future net cash flows	2,850
10% annual discount for estimated timing of cash flows	(834)
Standardized measure of discounted future net cash flows	$ 2,016
At December 31, 2010	
Future cash inflows	$ 4,141
Future production costs	(1,140)
Future development costs	(342)
Future Ghanaian tax expenses(1)	(618)
Future net cash flows	2,041
10% annual discount for estimated timing of cash flows	(511)
Standardized measure of discounted future net cash flows	$ 1,530
At December 31, 2009	
Future cash inflows	$ 3,098
Future production costs	(990)
Future development costs	(630)
Future Ghanaian tax expenses(1)	(351)
Future net cash flows	1,127
10% annual discount for estimated timing of cash flows	(429)
Standardized measure of discounted future net cash flows	$ 698

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Supplemental Oil and Gas Data (Unaudited)

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana (In millions)
Balance at December 31, 2009	$ 698
Net changes in prices	1,055
Net changes in production costs	(150)
Net changes in development costs	288
Extensions and discoveries	(12)
Net change in Ghanaian tax expenses(1)	(267)
Accretion of discount	(82)
Balance at December 31, 2010	$ 1,530
Sales and Transfers 2011	(583)
Net changes in prices and costs	1,547
Previous estimated development costs incurred during the period	175
Net changes in development costs	(489)
Revisions of previous quantity estimates	2
Changes in production timing	(66)
Net change in Ghanaian tax expenses(1)	(248)
Accretion of discount	199
Redetermination(2)	92
Changes in timing and other	(143)
Balance at December 31, 2011	$ 2,016

(1) Standardized Measure includes the effects of both future income tax expense related to the Company's proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level on future net revenues and future tax expense levied at an asset level (in the Company's case, future Ghanaian tax expense levied under the WCTP and DT PAs). As the Company has been a tax exempted company incorporated pursuant to the laws of the Cayman Islands to date and is now a tax exempted company incorporated pursuant to the laws of Bermuda since the completion of the corporate reorganization, and as the Company's intermediate subsidiaries positioned between it and the subsidiary that is a signatory to the WCTP and DT PAs will continue to be tax exempted companies, the Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2011, 2010 and 2009, respectively, only reflect the effects of futureGhanaian tax expense levied under the WCTP and DT PAs.

(2) Relates to an increase in our Jubilee Field unit interest (see Note 4—Jubilee Field Unitization).

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Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2011				
Revenues	$ 95,410	$ 126,853	$ 232,845	$ 221,672
Expenses	163,572	124,409	130,588	159,168
Net income (loss)	(54,651)	(9,091)	51,776	34,323
Net income (loss) attributable to common shareholders/unit holders	(71,498)	(16,686)	51,776	34,323
Net income (loss) attributable to common shareholders/unit holders per share, as restated(1):				
Basic (the quarter ended June 30 represents the period from May 16, 2011 to June 30, 2011	N/A	(0.14)	0.13	0.09
Diluted (the quarter ended June 30 represents the period from May 16, 2011 to June 30, 2011	N/A	(0.14)	0.13	0.09
2010				
Revenues	$ 2,443	$ 1,910	$ 1,988	$ 2,999
Expenses	67,422	34,788	84,543	145,367
Net income (loss)	(65,206)	(32,483)	(82,549)	(65,434)
Net income (loss) attributable to common unit holders	(80,951)	(48,679)	(99,210)	(94,145)
Net income (loss) attributable to common unit holders per share:				
Basic	N/A	N/A	N/A	N/A
Diluted	N/A	N/A	N/A	N/A

(1) See Notes 2 and 16 to the consolidated financial statements

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

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 upon this evaluation, as of the end of the period covered by this report, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were not effective, because of the material weakness below relating to our internal control over financial reporting. In light of this material weakness, the Company performed additional analysis and post-closing procedures to ensure its financial statements are prepared in accordance with generally accepted accounting principles.

A material weakness in internal control over financial reporting is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis by the Company's internal controls.

During the quarter ended December 31, 2011, management determined that 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.

We have determined that this deficiency constitutes a "material weakness" in our internal control over financial reporting. We have advised our independent auditors, who concur with our determination, and our audit committee of this deficiency in our internal control over financial reporting, and the fact that this deficiency constitutes a "material weakness."

Management's Annual Report on Internal Control over Financial Reporting. This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Evaluation of Changes in Internal Control over Financial Reporting. The remediation efforts, as outlined below, are designed to address the material weakness identified by management and to strengthen our internal control over financial reporting.

There were no changes in our internal control over financial reporting, other than those stated below, during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control 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 (which will be due in March 2013).

Beginning in the fourth quarter of 2011, and continuing into 2012, we have implemented the following remediation steps to address the material weakness discussed above and to improve our internal control over financial reporting:

- improved procedures for the calculation and reconciliation process of our income tax provision related to our treatment of unrealized derivative losses, including validation of underlying supporting data;

- adding additional personnel, including a Tax Manager, to prepare the income tax provision, allowing our Global Tax Manager to review the income tax provision to decrease the risk of unidentified errors and increase the accuracy of the information in our financial statements; and

- enhanced quarterly management review of the calculation of the income tax provision and underlying supporting data.

Additionally, in 2012, we plan to implement an additional internal control process that will require in-depth income tax discussion and analysis following any significant transaction or any change in our tax policy. While we have taken steps to remediate the material weakness, as of December 31, 2011, the Company had not yet completed its assessment as to whether the material weakness had been fully remediated.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during May 2012 and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during May 2012 and is incorporated herein by reference.

Item 12. Security of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during May 2012 and is incorporated herein by reference.

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

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during May 2012 and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during May 2012 and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial statements

The financial statements filed as part of the Annual Report on Form 10-K are listed in the accompanying index to consolidated financial statements in Item 8, Financial Statements and Supplementary Data.

(2) Financial statement schedules

Schedule I—Condensed Parent Company Financial Statements

Under the terms of agreements governing the indebtedness of subsidiaries of Kosmos Energy Ltd. for 2011, 2010 and 2009 (collectively "KEL," the "Parent Company"), such subsidiaries are restricted from making dividend payments, loans or advances to KEL. Schedule I of Article 5-04 of Regulation S-X requires the condensed financial information of the Parent Company to be filed when the restricted net assets of consolidated subsidiaries exceed 25 percent of consolidated net assets as of the end of the most recently completed fiscal year.

The following condensed parent-only financial statements of KEL have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X and included herein. The Parent Company's 100% investment in its subsidiaries has been recorded using the equity basis of accounting in the accompanying condensed parent-only financial statements. The condensed financial statements should be read in conjunction with the consolidated financial statements of Kosmos Energy Ltd. and subsidiaries and notes thereto.

The terms "Kosmos," the "Company," and similar terms when used in the present tense or prospectively or for historical periods since May 16, 2011 refer 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.

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY BALANCE SHEETS

(In thousands, except share data)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 352,872	$ —
Prepaid expenses and other	394	—
Total current assets	353,266	—
Investment in subsidiaries at equity	665,096	363,507
Total assets	$ 1,018,362	$ 363,507
Liabilities and shareholders' equity/unit holdings equity		
Current liabilities:		
Accounts payable to subsidiaries	$ 1,158	$ —
Total current liabilities	1,158	—
Convertible preferred units, 100,000,000 units authorized:		
Series A—zero and 30,000,000 units issued at December 31, 2011 and 2010, respectively	—	383,246
Series B—zero and 20,000,000 units issued at December 31, 2011 and 2010, respectively	—	568,163
Series C—zero and 884,956 units issued at December 31, 2011 and 2010, respectively	—	27,097
Shareholders' equity/unit holdings equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2011 and 2010	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 390,530,946 and zero issued at December 31, 2011 and 2010, respectively	3,905	—
Common units, 100,000,000 units authorized; zero and 19,069,662 issued at December 31, 2011 and 2010, respectively	—	516
Additional paid-in capital	1,629,453	—
Accumulated deficit	(616,148)	(615,515)
Treasury stock, at cost, 649,818 and zero shares at December 31, 2011 and 2010, respectively	(6)	—
Total shareholders' equity/unit holdings equity	1,017,204	(614,999)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	$ 1,018,362	$ 363,507

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	December 31, 2011	2010	2009
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Interest income	248	44	15
Total revenues and other income	248	44	15
Costs and expenses:			
General and administrative	5,064	21,187	11,580
General and administrative—related party	—	16,830	10,663
Depreciation and amortization	—	—	39
Other expenses, net	10	2	(14)
Equity in (earnings) losses of subsidiaries	(27,183)	207,697	57,494
Total costs and expenses	(22,109)	245,716	79,762
Income (loss) before income taxes	22,357	(245,672)	(79,747)
Income tax expense	—	—	—
Net income (loss)	$ 22,357	$ (245,672)	$ (79,747)

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2011	2010	2009
Operating activities			
Net income (loss)	$ 22,357	$ (245,672)	$ (79,747)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in (earnings) losses of subsidiaries	(27,183)	207,697	57,494
Depreciation and amortization	—	—	39
Equity-based compensation	50,966	13,791	3,468
Changes in assets and liabilities:			
(Increase) decrease in prepaid expenses and other	(394)	15	32
(Increase) decrease due to/from related party	1,158	3,878	(10,171)
Increase in accrued liabilities	—	213	213
Net cash provided by (used in) operating activities	46,904	(20,504)	(28,672)
Investing activities			
Investment in subsidiaries	(274,406)	(30,722)	(245,496)
Other property	—	2	(2)
Net cash used in investing activities	(274,406)	(30,720)	(245,498)
Financing activities			
Net proceeds from the initial public offering	580,374	—	—
Net proceeds from issuance of units	—	—	325,344
Net cash provided by financing activities	580,374	—	325,344
Net increase (decrease) in cash and cash equivalents	352,872	(51,224)	51,174
Cash and cash equivalents at beginning of period	—	51,224	50
Cash and cash equivalents at end of period	$ 352,872	$ —	$ 51,224

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2011, 2010 and 2009

		Additions			
	Balance January 1,	Charged to Costs and Expenses	Charged To Other Accounts	Deductions From Reserves	Balance December 31,
Description					
2011					
Allowance for doubtful receivables	$ 39,782	$ (39,782)	$ —	$ —	$ —
Allowance for deferred tax asset	$ 30,140	$ 19,362	$ —	$ —	$ 49,502
2010					
Allowance for doubtful receivables	$ —	$ 39,782	$ —	$ —	$ 39,782
Allowance for deferred tax asset	$ 33,749	$ (3,609)	$ —	$ —	$ 30,140
2009					
Allowance for doubtful receivables	$ —	$ —	$ —	$ —	$ —
Allowance for deferred tax asset	$ 19,131	$ 14,618	$ —	$ —	$ 33,749

Schedules other than Schedule I and Schedule II have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or the notes to consolidated financial statements.

(3) Exhibits

See "Index to Exhibits" on page 151 for a description of the exhibits filed as part of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KOSMOS ENERGY LTD.

Date: January 31, 2013	By:	/s/ W. GREG DUNLEVY
		W. Greg Dunlevy
		Chief Financial Officer and Executive Vice President

INDEX OF EXHIBITS

Exhibit Number	Description of Document
3.1	Certificate of Incorporation of the Company (filed as Exhibit 3.1 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
3.2	Memorandum of Association of the Company (filed as Exhibit 3.2 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
3.3	Bye-laws of the Company (filed as Exhibit 4 to the Company's Registration Statement on Form 8-A filed May 6, 2011 (File No. 001-35167), and incorporated herein by reference).
3.4	Fourth Amended and Restated Operating Agreement of the Predecessor, as amended (filed as Exhibit 3.4 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
3.5	Memorandum of Association of the Predecessor (filed as Exhibit 3.5 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
3.6	Articles of Association of the Predecessor (filed as Exhibit 3.6 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
4.1	Specimen share certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
9.1	Form of Shareholders Agreement (filed as Exhibit 9.1 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.1	Petroleum Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 22, 2004 among the GNPC, Kosmos Ghana and the E.O. Group (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.2	Operating Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 27, 2004 between Kosmos Ghana and E.O. Group (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.3	Petroleum Agreement in respect of the Deepwater Tano Contract Area dated March 10, 2006 among GNPC, Tullow Ghana, Sabre and Kosmos Ghana (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.4	Joint Operating Agreement in respect of the Deepwater Tano Contract Area, Offshore Ghana dated August 14, 2006, among Tullow Ghana, Sabre Oil and Gas Limited, and Kosmos Ghana (filed as Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).

Exhibit Number	Description of Document
10.5	Assignment Agreement in respect of the Deepwater Tano Block dated September 1, 2006, among Anadarko WCTP and Kosmos Ghana (filed as Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.6	Unitization and Unit Operating Agreement covering the Jubilee Field Unit located offshore the Republic of Ghana dated July 13, 2009, among GNPC, Tullow, Kosmos Ghana, Anadarko WCTP, Sabre and E.O. Group (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.7	Atwood Hunter Offshore Drilling Contract dated June 23, 2008 among Kosmos Ghana, Alpha Offshore Drilling Services Company and Noble Energy EG Ltd., as amended (filed as Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
10.8	Ndian River Production Sharing Contract dated November 20, 2006 between the Republic of Cameroon and Kosmos Cameroon (filed as Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.9	Decree 2005/249 dated June 30, 2005 granting Perenco and SNH the Kombe-N'sepe Permit (filed as Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.10	Contract of Association relating to the Kombe-N'sepe Permit dated December 11, 1997 between the Republic of Cameroon, CMS Nomeco Cameroon, Globex Cameroon and SNH (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.11	Convention of Establishment relating to the Kombe-N'sepe Permit dated December 11, 1997 between the Republic of Cameroon, CMS Nomeco Cameroon and Globex Cameroon (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.12	Deed of Assignment of the Kombe-N'sepe Permit, Contract of Association and Convention of Establishment dated November 16, 2005 between Perenco and Kosmos Cameroon (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.13	Agreement on the Management of Petroleum Operations (JOA) covering the Kombe-N'sepe Permit dated July 3, 2008 among SNH, Perenco and Kosmos Cameroon (filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.14	Petroleum Agreement regarding the exploration for and exploitation of hydrocarbons in the area of interest named Boujdour Offshore dated May 3, 2006 between ONHYM and Kosmos Morocco (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.15	Association Contract regarding the exploration for and exploitation of hydrocarbons in the Boujdour Offshore Block dated May 3, 2006 between ONHYM and Kosmos Morocco (filed as Exhibit 10.15 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).

Exhibit Number	Description of Document
10.16	Memorandum of Understanding regarding a new petroleum agreement covering certain areas of the Boujdour Offshore Block dated September 27, 2010 between ONHYM and Kosmos Morocco (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.17	Facility Agreement, dated March 28, 2011 among Kosmos Finance International, Kosmos Operating, Kosmos International, Kosmos Development and Kosmos Ghana and the various financial institutions and others party thereto (filed as Exhibit 10.17 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
10.20	Intercreditor Agreement, dated March 28, 2011 among BNP Paribas, Kosmos Finance International, Kosmos Operating, Kosmos International, Kosmos Development, Kosmos Ghana and the various financial institutions and others party thereto (filed as Exhibit 10.20 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
10.21†	Form of Long Term Incentive Plan (filed as Exhibit 10.21 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.22†	Form of Annual Incentive Plan (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.23†	Form of Non-Qualified Stock Option Award Agreement (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.24†	Form of Restricted Stock Award Agreement (Exchange) (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.25†	Form of Restricted Stock Award Agreement (Service Vesting) (filed as Exhibit 10.25 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.26†	Form of Restricted Stock Award Agreement (Performance Vesting) (filed as Exhibit 10.26 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.27	Form of Director Indemnification Agreement (filed as Exhibit 10.27 to the Company's Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
10.28†	Retirement Agreement dated December 17, 2010 between Kosmos Energy, LLC, Kosmos Energy Holdings, James C. Musselman, Musselman-Kosmos, Ltd. and funds affiliated with Warburg Pincus LLC and The Blackstone Group L.P. (filed as Exhibit 10.28 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.29†	Consulting Agreement dated November 17, 2010 between Kosmos Energy Holdings and John R. Kemp (filed as Exhibit 10.29 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).

Exhibit Number	Description of Document
10.30	Letter agreement, dated May 4, 2010 among Tullow Ghana Limited, Anadarko WCTP Company and Kosmos Ghana (filed as Exhibit 10.31 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
10.31	Settlement Agreement, dated December 18, 2010 among Kosmos Ghana, Ghana National Petroleum Corporation and the Government of the Republic of Ghana (filed as Exhibit 10.32 to the Company's Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
10.32†	Participation Agreement date June 1, 2004 between Kosmos Ghana and E.O. Group Limited (filed as Exhibit 10.33 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
10.33†	Consulting Agreement dated October 31, 2011 between Kosmos Energy Ltd. and John R. Kemp (filed as Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 filed March 1, 2012 (File No. 001-35167), and incorporated herein by reference).
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 filed March 1, 2012 (File No. 001-35167), and incorporated herein by reference).
21.1	List of Subsidiaries (filed as Exhibit 21.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 filed March 1, 2012 (File No. 001-35167), and incorporated herein by reference).
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of Netherland, Sewell & Associates, Inc. (filed as Exhibit 99.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 filed March 1, 2012 (File No. 001-35167), and incorporated herein by reference).
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.

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* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-3, No. 333-182280, and Form S-8, No. 333-174234, of Kosmos Energy Ltd. of our report dated March 1, 2012, except as to the presentation of net income per share attributable to common shareholders as discussed in Notes 2 and 16, as to which the date is January 28, 2013, with respect to the consolidated financial statements and schedules of Kosmos Energy Ltd., included in this Amendment to the Annual Report (Form 10-K/A) for the year ended December 31, 2011.

/s/ Ernst & Young LLP

Dallas, Texas
January 28, 2013

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the reference of our firm and to the use of our reports effective December 31, 2011; December 31, 2010; and December 31, 2009, dated February 16, 2012; February 3, 2011; and February 2, 2010, respectively, in the Kosmos Energy Annual Report on Form 10-K for the year ended December 31, 2011, to be filed as Amendment No. 1 with the U. S. Securities and Exchange Commission on or about January 28, 2013.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (SCOTT) REES III, P.E.

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
January 28, 2013

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Exhibit 31.1

Certification of Chief Executive Officer

I, Brian F. Maxted, certify that:

1. I have reviewed this Amendment No. 1 to the annual report on Form 10-K of Kosmos Energy Ltd.;

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

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

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

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

   (b) [Reserved];

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

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

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

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

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

Date: January 31, 2013

/s/ BRIAN F. MAXTED

Brian F. Maxted
Director and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

Certification of Chief Financial Officer

I, W. Greg Dunlevy, certify that:

1. I have reviewed this Amendment No. 1 to the annual report on Form 10-K of Kosmos Energy Ltd.;

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

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

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

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

   (b) [Reserved];

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

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

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

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

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

Date: January 31, 2013

/s/ W. GREG DUNLEVY

W. Greg Dunlevy
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the accompanying Amendment No. 1 to the annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian F. Maxted, Director and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

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

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

Date: January 31, 2013

/s/ BRIAN F. MAXTED

Brian F. Maxted
Director and Chief Executive Officer
(Principal Executive Officer)

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

QuickLinks

Exhibit 32.1

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

Exhibit 32.2

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

In connection with the accompanying Amendment No. 1 to the annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Greg Dunlevy, Chief Financial Officer and Executive Vice President of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

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

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

Date: January 31, 2013

/s/ W. GREG DUNLEVY

W. Greg Dunlevy
Chief Financial Officer and Executive Vice President
(Principal Financial Officer)

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