

Kosmos Energy Ltd.  
Form 10-K  
February 24, 2014

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**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

**FORM 10-K**

(Mark One)

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

For the fiscal year ended December 31, 2013

**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**  
(State or other jurisdiction of  
incorporation or organization)

**98-0686001**  
(I.R.S. Employer  
Identification No.)

**Clarendon House**  
**2 Church Street**  
**Hamilton, Bermuda**  
(Address of principal executive offices)

**HM 11**  
(Zip Code)

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

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

<b>Title of each class</b>	<b>Name of each exchange on which registered:</b>
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

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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                       Smaller reporting company   
(Do not check if a 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 \$951,286,205.

The number of the registrant's Common Shares outstanding as of February 18, 2014 was 387,595,931.

### DOCUMENTS INCORPORATED BY REFERENCE

Part III, Items 10-14, is incorporated by reference from the Proxy Statement for the Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2013.

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

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*Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy 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.*

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**KOSMOS ENERGY LTD.  
GLOSSARY AND SELECTED 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.

<i>"2D seismic data"</i>	Two-dimensional seismic data, serving as interpretive data that allows a view of a vertical cross-section beneath a prospective area.
<i>"3D seismic data"</i>	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.
<i>"API"</i>	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.
<i>"ASC"</i>	Financial Accounting Standards Board Accounting Standards Codification.
<i>"ASU"</i>	Financial Accounting Standards Board Accounting Standards Update.
<i>"Barrel" or "Bbl"</i>	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
<i>"BBbl"</i>	Billion barrels of oil.
<i>"BBoe"</i>	Billion barrels of oil equivalent.
<i>"Bcf"</i>	Billion cubic feet.
<i>"Boe"</i>	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.
<i>"Boepd"</i>	Barrels of oil equivalent per day.
<i>"Bopd"</i>	Barrels of oil per day.
<i>"Bwpd"</i>	Barrels of water per day.
<i>"Debt cover ratio"</i>	The "debt cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) total long-term debt less cash and cash equivalents and restricted cash, to (y) the aggregate EBITDAX (see below) of the Company for the previous twelve months.
<i>"Developed acreage"</i>	The number of acres that are allocated or assignable to productive wells or wells capable of production.
<i>"Development"</i>	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.

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<i>"Dry hole"</i>	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
<i>"EBITDAX"</i>	Net income (loss) plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) equity-based compensation expense, (4) (gain) loss on commodity derivatives, (5) (gain) loss on sale of oil and gas properties, (6) interest (income) expense, (7) income taxes, (8) loss on extinguishment of debt, (9) doubtful accounts expense, and (10) similar items.
<i>"E&amp;P"</i>	Exploration and production.
<i>"FASB"</i>	Financial Accounting Standards Board.
<i>"Farm-in"</i>	An agreement whereby an oil company acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and for taking on a portion of the drilling costs of one or more specific wells or other performance by the assignee as a condition of the assignment.
<i>"Farm-out"</i>	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash or for the assignee taking on a portion of the drilling costs of one or more specific wells and/or other work as a condition of the assignment.
<i>"Field life cover ratio"</i>	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 certain 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.
<i>"FPSO"</i>	Floating production, storage and offloading vessel.
<i>"Ghana Obligors"</i>	Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Finance International, Kosmos Energy Development, Kosmos Energy Ghana HC and an "Obligor" from time to time, as defined under the Facility Agreement, as amended and restated.
<i>"Interest cover ratio"</i>	The "interest cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) the aggregate EBITDAX (see above) of the Company for the previous twelve months, to (y) interest expense less interest income for the Company for the previous twelve months.
<i>"Loan life cover ratio"</i>	The "loan life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the final maturity date of the Facility plus the net present value of capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility.

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<i>"MBbl"</i>	Thousand barrels of oil.
<i>"Mcf"</i>	Thousand cubic feet of natural gas.
<i>"Mcfpd"</i>	Thousand cubic feet per day of natural gas.
<i>"MMBbl"</i>	Million barrels of oil.
<i>"MMBoe"</i>	Million barrels of oil equivalent.
<i>"MMcf"</i>	Million cubic feet of natural gas.
<i>"Natural gas liquid" or "NGL"</i>	Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.
<i>"Petroleum contract"</i>	A contract in which the owner of hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
<i>"Petroleum system"</i>	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
<i>"Plan of development" or "PoD"</i>	A written document outlining the steps to be undertaken to develop a field.
<i>"Productive well"</i>	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.
<i>"Prospect(s)"</i>	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.
<i>"Proved reserves"</i>	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).
<i>"Proved developed reserves"</i>	Proved developed reserves are those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

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<i>"Proved undeveloped reserves"</i>	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.
<i>"Reconnaissance contract"</i>	A contract in which the owner of hydrocarbons gives an E&P company rights to perform evaluation of existing data or potentially acquire additional data but does not convey an exclusive option to explore for, develop, and/or produce hydrocarbons from the lease area.
<i>"Shelf margin"</i>	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
<i>"Structural trap"</i>	A structural trap 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.
<i>"Structural-stratigraphic trap"</i>	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.
<i>"Stratigraphy"</i>	The study of the composition, relative ages and distribution of layers of sedimentary rock.
<i>"Stratigraphic trap"</i>	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.
<i>"Submarine fan"</i>	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.
<i>"Three-way fault trap"</i>	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
<i>"Trap"</i>	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
<i>"Undeveloped acreage"</i>	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains discovered resources.

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**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, Ireland, Mauritania, Morocco (including Western Sahara) 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 and production risks and other operational and environmental hazards;

current and future government regulation of the oil and gas industry;



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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;

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military operations, civil unrest, terrorist acts, wars or embargoes;

the cost and availability of adequate insurance coverage;

our vulnerability to severe weather events;

our ability to meet our obligations under the agreements governing our indebtedness;

the availability and cost of financing and refinancing our indebtedness;

the amount of collateral required to be posted from time to time in our hedging transactions;

our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and

other risk factors discussed in the "Item 1A. Risk Factors" section of this annual report on Form 10-K.

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

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**PART I**

**Item 1. Business**

**General**

We are a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margin. Our assets include existing production and other major development projects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Ireland, Mauritania, Morocco (including Western Sahara) and Suriname. Kosmos is listed on the New York Stock Exchange ("NYSE") and is traded under the ticker symbol KOS.

Following our formation in 2003, we acquired multiple 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 in November 2010.

In the near-term, we are focused on maximizing production and cash flow from the Jubilee Field; developing the Tweneboa-Enyenra-Ntomme ("TEN") project which was approved by the Ministry of Energy in 2013; appraising our other discoveries in Ghana; and beginning a multi-year, exploration drilling program targeting several high impact opportunities.

**Our Business Strategy**

*Grow proved reserves and production through exploration, appraisal and development*

We plan to optimize production and further develop the Jubilee Field, bring the TEN development project to production and appraise the Mahogany, Teak, Akasa and Wawa discoveries. In May 2013, the government of Ghana approved the PoD over the TEN discoveries. The TEN project is expected to deliver first oil in 2016. In the event of a declaration of commerciality and approval of a plan of development over our Mahogany, Teak, Akasa and/or Wawa discoveries, we intend to develop these discoveries to grow proved reserves and production. We also plan to drill exploration prospects, with the intent to further grow proved reserves and production should discoveries be made.

*Successfully open and develop our offshore exploration plays*

We believe the prospects and leads potentially existing offshore Morocco, Mauritania, Suriname and Ireland provide a favorable opportunity to meaningfully create value. We anticipate drilling two to three play-opening exploratory wells per year in these basins beginning in 2014, depending on our analysis of seismic data covering the blocks, initial exploration drilling results and availability of drilling rigs and other required equipment and services. Depending on the results of these exploratory wells, additional wells may be drilled. Given the potential size of these prospects and leads, we believe that exploratory success in our operating areas could be significantly accretive to shareholder value.

*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 development personnel are critical 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 enables us to fully consider and understand both risk and reward, as well as deliberately and collectively pursue strategies that maximize value. We used this philosophy and approach to make

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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 optimally developing our discoveries to initial production***

We focus on field developments designed to deliver early learnings and accelerate production. 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. 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 also refines the 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 recovery 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.

For example, first oil production from the Jubilee Field commenced in November 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.

***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 use our systematic and proven geologically-focused approach to frontier and 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 initially focus. 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 Cretaceous petroleum systems across the Atlantic Margin, including play types that had previously been largely ignored. In addition, our exploration portfolio includes sub-salt plays, which has been the other recent successful play concept along the Atlantic Margin.

This approach and focus, coupled with a first mover advantage and our management and technical teams' reputation and relationships, provide a competitive advantage in identifying and accessing new strategic growth opportunities. We expect to continue seeking 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 our reach into other locations along the Atlantic Margin. We may farm-in to new venture opportunities to undertake exploration in emerging basins, new plays and fairways to enhance and optimize our portfolio.

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Consistent with this strategy, we may also evaluate potential corporate and asset acquisition opportunities as a source of new ventures to support 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 targets licenses over the particular basin or fairway 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. Kosmos also looks for 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 currently have operations in Africa, Europe and South America. Currently, all revenues are generated from our operations offshore Ghana.

***Ghana***

The West Cape Three Points Block ("WCTP Block") and Deepwater Tano Block ("DT Block") are located within the Tano Basin, offshore Ghana. This basin contains a proven world-class petroleum system as evidenced by our discoveries.

The 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.

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The primary reservoir 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.

#### *Our Ghanaian Discoveries*

Information about our Ghanaian discoveries is summarized in the following table.

Discoveries	License	Kosmos Participating Interest	Block Operator(s)	Stage	Type	Expected Year of PoD Submission(11)
<b>Ghana</b>						
Jubilee Field Phase 1 and Phase 1A(1)(2)	WCTP/DT(3)	24.0771%(5)	Tullow/Kosmos(7)	Production	Deepwater	2008/2011(2)
Jubilee Field subsequent phases(1)	WCTP/DT(3)	24.0771%(5)	Tullow/Kosmos(7)	Development	Deepwater	2014(8)
Mahogany	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2015(9)
Teak	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2015(9)
Akasa	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2015(9)
TEN	DT	17.0000%(6)	Tullow	Development	Deepwater	2012(10)
Wawa	DT	18.0000%(4)	Tullow	Appraisal	Deepwater	2015

- (1) For information concerning our estimated proved reserves in the Jubilee Field as of December 31, 2013, see " Our Reserves."
- (2) The Jubilee Phase 1 and Phase 1A PoDs were approved by Ghana's Ministry of Energy in 2009 and 2012, respectively. The Jubilee Phase 1 and Phase 1A PoDs detail the necessary wells and infrastructure to develop three of the reservoirs within the Jubilee Field. Oil production from the Jubilee Field offshore Ghana commenced in November 2010, and we received our first oil revenues in early 2011.
- (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 "UUAO") in July 2009 with Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The UUAO 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 participating interests in the Jubilee Field pursuant to the terms of the UUAO. 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 License Agreements Jubilee Field Unitization." GNPC exercised its WCTP PA and DT PA options, with respect to the Jubilee Unit, to 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. Our paying interest on development activities in the Jubilee Field is 26.85484%.
- (6) In February 2013, GNPC exercised its DT PA option, with respect to TEN, to acquire an additional paying interest of 5.0%. The TEN interest percentage gives effect to the exercise of such option. Our paying interest on development activities in TEN is 19%.
- (7) 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 License Agreements Jubilee Field Unitization."
- (8) We submitted the Jubilee Full Field Development Plan ("JFFDP") to Ghana's Minister of Energy in December 2012 and subsequently withdrew based on discussions with the government of Ghana. A PoD providing for development of the next phase within the Jubilee Field is expected to be submitted during 2014, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all.
- (9)

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Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished.

(10)

The DT Block partners submitted a declaration of commerciality and a PoD to Ghana's Ministry of Energy in November 2012. In May 2013, the government of Ghana approved the PoD over the TEN discoveries. Development of TEN will include the drilling and completion of up to 24 development wells; half of the wells are designed as producers and the remainder as water or gas injectors to support ultimate field recoveries. The TEN project is expected to deliver first oil in 2016.

(11)

In interpreting this information, 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" 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 participating 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."

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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. Any party to the Jubilee UUOA with more than a 10% Jubilee Unit Interest 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 "Item 8. Financial Statements and Supplementary Data Note 4 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 FPSO is designed to provide water and natural gas injection to support reservoir pressure and to process and store oil. 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 "Kwame Nkrumah" 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 two existing producing reservoirs and development of the three remaining reservoirs to maximize ultimate recovery and asset value.

Production from the Phase 1 development commenced in November 2010, with Kosmos' first lifting in early 2011. As production from the field grew through 2011, certain near-wellbore productivity issues were identified, impacting several of the Phase 1 production wells. The Jubilee Unit partners identified a means of successfully mitigating the near-wellbore productivity issues experienced in the Jubilee production wells through stimulation treatments. We received approval for the Phase 1A PoD of the Jubilee Field and production from Phase 1A development commenced in late 2012. The Phase 1A development includes the drilling of up to eight additional wells consisting of up to five production wells and three water injection wells. Five wells (three producers and two water injection wells) are online. Program execution is expected to be completed in 2014.

The Government of Ghana is in the process of completing the construction and connection of a gas pipeline from the Jubilee Field to transport natural gas to the mainland for processing and sale; however, to date, the construction of the pipeline and the onshore plant has not been



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completed and the Company is presently unable to predict with certainty when completion will occur, as several previous completion dates have passed. In the absence of a pipeline to remove large quantities of natural gas from the Jubilee Field in order to maximize production levels it is anticipated that we will need to flare such natural gas. Currently, we have not been issued an amended permit from the Ghana Environmental Protection Agency ("Ghana EPA") to flare natural gas produced from the Jubilee Field in substantial quantities. If we are unable to resolve issues related to the continuous removal of associated natural gas in large quantities from the Jubilee Field, our oil production will be negatively impacted. See "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."

During 2013, we experienced mechanical issues in the Jubilee Field, including failures of our water injection facilities on the FPSO and water and gas injection wells. This equipment downtime negatively impacted oil production during the year.

Oil production from the Jubilee Field averaged approximately 97,500 barrels of oil per day during 2013. We submitted the JFFDP to Ghana's Minister of Energy in December 2012 and subsequently withdrew based on discussions with the government of Ghana. A PoD providing for development of the next phase within the Jubilee Field is expected to be submitted during 2014, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all.

**WCTP Block Discoveries**

Mahogany 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.

Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished.

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 Teak-4A appraisal well was completed in May 2012. The well encountered non-commercial reservoirs and accordingly was plugged and abandoned.

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. We believe that the Akasa-2A appraisal well successfully

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identified the down dip water contact associated with the Akasa-1 discovery as intended. Should the Akasa discovery progress to a development, the Akasa-2A appraisal well is expected to be utilized in the development as a water injection well. However, since the Akasa-2A appraisal well did not encounter oil or gas reserves sufficient to be utilized as a producing well, accounting rules require that the costs associated with the Akasa-2A appraisal well be impaired. Fluid samples recovered from the well indicate an oil gravity of 38 degrees API.

Following additional appraisal 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. We expect that any future development of the WCTP Block discoveries would be a subsea tie-back through the Jubilee FPSO.

Kosmos is the operator of the WCTP Block and holds a 30.875% participating interest. The WCTP PA, which governs our activities related to the WCTP Block, and for commercial development areas, has a duration of 30 years from its effective date of July 22, 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 relinquished ("WCTP Relinquishment Area"). Our existing discoveries within the WCTP Block (Akasa, Mahogany and Teak) have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase for these areas while commerciality is being established. Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished.

**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, Enyenra-3A, Enyenra-4A and Enyenra-6A 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

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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.

In November 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries (includes Tweneboa, Enyenra and Ntomme). In May 2013, the government of Ghana approved the PoD over the TEN discoveries. Development of TEN will include the drilling and completion of up to 24 development wells, half of the wells designed as producers and the remainder as water or gas injectors to support ultimate field recoveries. The TEN development is expected to deliver first oil in 2016. Future development of gas resources at TEN is anticipated following the commencement of oil startup.

The Wawa-1 exploration well intersected oil and gas-condensate in a Turonian-aged turbidite channel system. Pressure data shows that it is a separate accumulation from the TEN fields. Following additional appraisal and evaluation, a decision regarding the commerciality of the Wawa discovery will be made by the DT Block partners. Should the 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.

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 and for commercial development areas therein, has a duration of 30 years from its effective date of July 19, 2006. The seven-year exploration phase of the DT PA expired in January 2013. Our existing discoveries within the DT Block (Tweneboa, Enyenra, Ntomme and Wawa) 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 for these areas while commerciality is being determined.

*Ireland*

We have identified the Porcupine Basin Offshore Ireland as an underexplored basin with the potential for large oil hydrocarbon accumulations in our core Cretaceous stratigraphic play concept.

The Porcupine Basin is a Jurassic aged rift basin located on the eastern Atlantic margin offshore Southwest Ireland. Previous exploration was focused on Jurassic and Tertiary aged sandstones located in the shallow water portions of the basin. These wells encountered Jurassic, Cretaceous and Tertiary reservoirs, Jurassic source rocks and oil and gas; however, no commercial developments have taken place in the basin. We have identified a number of geologic features of Cretaceous age on vintage 2D seismic data which have play potential similar to the features identified in our Atlantic Margin acreage.

In April 2013, we entered into a farm-in agreement with Antrim Energy Inc. ("Antrim"), whereby we acquired a 75% participating interest and operatorship, covering Licensing Option 11/5 offshore the west coast of Ireland. As part of the agreement, we reimbursed a portion of previously-incurred exploration costs and are paying the partner's share of 3D seismic costs.

In April 2013, we entered into a farm-in agreement with Europa Oil & Gas (Holdings) plc ("Europa"), whereby we acquired an 85% participating interest and operatorship, covering Licensing Option 11/7 and 11/8 offshore the west coast of Ireland. As part of the agreement, we reimbursed a portion of previously-incurred exploration costs and are paying the partner's share of 3D seismic costs. Contingent upon an election by us and our partner to enter into a subsequent exploration drilling phase on one or both of the blocks, we will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap of \$90.0 million and \$110.0 million, respectively, on each block.

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In July 2013, Ireland granted us Frontier Exploration Licenses 1-13, 2-13, and 3-13 pursuant to Licensing Options 11/5, 11/7 and 11/8. The term of each contract is 15 years unless surrendered or revoked, and is divided into an initial phase of three years, and three subsequent phases of four years each. Relinquishment of 25% of the existing area is required at the end of the first phase and 50% of the existing area at the end of the second phase. Three months before the end of each phase, we must propose a work program for the subsequent phase for the approval of the Minister of Communications, Energy and Natural Resources. The second phase work program must include an exploration well. The contract area must be surrendered if a second exploration well has not been commenced by the end of the third phase. Upon entering these Frontier Exploration Licenses, we and the other block partners relinquished approximately 25% of the acreage covered by the Licensing Options.

We completed a 3D seismic data acquisition program of approximately 5,000 square kilometers over these blocks and in the surrounding area in October 2013. The processing of this seismic data is expected to be completed in 2014.

We are currently assessing prospectivity on license areas in Ireland, and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, processing seismic information to assess the prospectivity for these license areas.

*Mauritania*

In June 2012, we successfully acquired three new petroleum contracts offshore Mauritania. The new petroleum contracts are Offshore Blocks C8, C12 and C13. We are the operator and hold a 90% participating interest in all blocks. The initial period of each contract is four years and may be extended to June 2022 at our election if certain requirements are met. We are currently in the first exploration period of the blocks, expiring in June 2016. In the event of commercial success, we have the right to develop and produce oil for 25 years and gas for 30 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Offshore Blocks C8, C12 and C13 are located on the western margin of the Mauritania Salt Basin. The blocks are adjacent to a proven petroleum system with the primary targets being Cretaceous sediments in structural and stratigraphic traps. Available geologic and geophysical data has led to the interpretation and mapping of possible Cretaceous basin floor fans in possible trapping geometries outboard of the Salt Basin. The Cretaceous source rocks penetrated by wells and typed to oils in the Mauritania Salt Basin are believed to be the same age as those which charge other oil and gas fields in the Late Cretaceous of West Africa.

Mauritania is located in Northwest Africa and its continental shelf is part of the Mauritania-Senegal-Guinea Bissau (MSGBC) Atlantic margin basin. This is a Triassic salt basin which formed at the onset of rifting and contains an overlying Jurassic, Cretaceous and Tertiary passive margin sequence of limestones, sandstone and shales.

A number of exploration wells have been drilled in shallow to moderate water depths in the basin and have resulted in oil and gas discoveries in both Tertiary and Cretaceous aged features. One of these, the Chinguetti Field is currently producing.

Our acreage is located outboard of the producing area in three licenses which vary in water depth from 1,500 to 3,000 meters. These blocks cover an aggregate area of approximately 6.6 million acres and are focused beyond the edge of the salt province on the basin floor where potentially reservoir bearing Mid to Late Cretaceous aged stratigraphy has been identified on vintage 2D seismic data in areas where there is evidence for trapping geometries. Our understanding of the blocks will be refined with additional seismic data acquisition over the areas where a number of leads with considerable petroleum potential have been identified.

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In May 2013, we completed a 2D seismic data acquisition program on approximately 6,000 line-kilometers, covering Blocks C8, C12 and C13. In November 2013, we completed a 3D seismic program of approximately 10,300 square kilometers over portions of Blocks C8 and C12. Processing of this seismic data is expected to be completed in 2014.

We are currently assessing prospectivity on license areas in Mauritania, and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, processing seismic information to assess the prospectivity for these license areas.

*Morocco (including Western Sahara)*

During 2011, we acquired two new petroleum contracts, renewed an existing petroleum contract and acquired a new reconnaissance contract (which was subsequently converted to a new petroleum contract) in Morocco. Our petroleum contracts include the Cap Boujdour Offshore block, which is within the Aaiun Basin, and the Essaouira Offshore block, the Foug Assaka Offshore block and the Tarhazoute Offshore block, which are within the Agadir Basin. We are the operator of these petroleum contracts and our initial participating interests were 75%, 37.5%, 37.5% and 75% for the Cap Boujdour Offshore block, the Essaouira Offshore block, the Foug Assaka Offshore block and the Tarhazoute Offshore block, respectively.

*Aaiun Basin*

The Cap Boujdour Offshore 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 distinct exploration fairways in this block, which provide substantial exploration opportunities. The main play elements of the prospectivity within the Cap Boujdour Offshore block consist of a Late Jurassic source rock, charging Early to Mid Cretaceous deepwater sandstones trapped in a number of different structural trends. In the inboard area a number of three-way fault closures are present which contain Early to Mid Cretaceous sandstone sequences some of which have been penetrated in wells on the continental shelf. Outboard of these fault trap trends, large four-way closure and combination structural stratigraphic traps are present in discrete northeast to southwest trending structurally defined fairways.

We are the operator of the Cap Boujdour Offshore block. We are currently in the first exploration period, which was recently extended to March 2014. The exploration phase may be extended up to eight years from the September 2011 effective date, or to September 2019. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In October 2013, we entered into a farm-out agreement with Capricorn Exploration & Development Company Limited, a wholly owned subsidiary of Cairn Energy PLC ("Cairn"), covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at \$25.0 million and one exploration well capped at \$100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at \$100.0 million per well. Additionally, Cairn will contribute \$12.3 million towards our future costs and, upon close of the transaction, \$0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator.

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*Agadir Basin*

We are the operator of the Fom Assaka Offshore, Essaouira Offshore and Tarhazoute Offshore blocks, which are located in the Agadir Basin. A working petroleum system has been established in the onshore area of the Agadir Basin based on onshore and shallow offshore wells. Existing well data and geological and geochemical studies have demonstrated the presence of Cretaceous source rocks in the acreage. Onshore production suggests that possible Jurassic source rocks are also present in the offshore Agadir Basin. The offshore Agadir Basin sediments are interpreted to comprise thick sequences of Lower to Upper Cretaceous age formations consisting of deep water channels and lobes. The interpreted prospects' trapping styles are varied and include pre-salt ponded slope fans, salt domes, salt cored anticlines and sub-salt structures.

In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013.

In August 2013, final government approvals and processes were completed for the acquisition of an additional 18.75% participating interest in the Fom Assaka block in the Agadir Basin offshore Morocco from Pathfinder Hydrocarbon Ventures Limited ("Pathfinder"), a wholly owned subsidiary of Fastnet Oil and Gas plc ("Fastnet"), one of our block partners.

In October 2013, we entered into three farm-out agreements with BP plc ("BP") covering our three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Fom Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of \$120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of \$120.0 million per well. Upon close of the transaction, BP shall also pay \$36.3 million for their share of past costs and \$8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Fom Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

We have recently completed interpretation of approximately 7,800 square kilometers of new and reprocessed 3D seismic data in our Fom Assaka Offshore and Essaouira Offshore blocks. During 2014, we plan to begin a seismic data acquisition program over the Tarhazoute Offshore and Essaouira Offshore blocks. We have identified numerous prospects in the Fom Assaka Offshore and Essaouira Offshore blocks. We plan to drill the FA-1 exploration well on the Eagle prospect during 2014.

The Fom Assaka Offshore block is currently in the first extension period of the exploration permit, which is for two and one-half years from its effective date (January 1, 2014) ending in June 2016. The exploration phase may be extended to July 2019 at our election. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

The Essaouira Offshore block is currently in the first exploration period, which is for two and one-half years from its effective date (November 8, 2011) ending in May 2014. The exploration phase may be extended to November 2019 at our election. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

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In October 2013, Kosmos executed a petroleum agreement with the Office National des Hydrocarbures et des Mines ("ONHYM"), the national oil company of the Kingdom of Morocco, covering the Tarhazoute Offshore block, to which the Company previously held certain exploration rights under a 2011 reconnaissance contract. Under the terms of the petroleum contract, the Company is the operator of the Tarhazoute Offshore block. ONHYM holds a 25% carried interest in the block through the exploration period. The Tarhazoute Offshore block is currently in the first exploration period, which is for two and one-half years from its effective date (December 9, 2013) ending in June 2016. The exploration phase may be extended for a total duration of eight years at our election and subject to our fulfilling specific work obligations, which include acquisition of 3D seismic data during the first period and drilling an exploration well in each of the subsequent periods. In the event of commercial success, the Company has the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation concession from the Government of Morocco, which may be extended for an additional period of 10 years under certain circumstances.

We are currently assessing prospectivity on the Tarhazoute Offshore block 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, processing seismic information to assess the prospectivity for these license areas.

*Suriname*

Our blocks in Suriname are located within the Guyana-Suriname Basin, along the Atlantic transform 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. 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.

We believe the play types offshore Suriname are relatively similar to those offshore West Africa and may contain subtle stratigraphic traps similar to those discovered offshore Ghana in the Jubilee field. Target reservoirs are Upper and Middle Cretaceous age basin floor fans and mid-slope channel sands which may have good lateral continuity. The Tambaredjo and Calcutta Fields onshore Suriname demonstrate that a working petroleum system exists in the area. Geological and geochemical studies suggest the hydrocarbons in these fields were generated in source rocks located in the offshore basin. The source rocks are believed to be similar in age to those which charged some of the fields offshore West Africa. Suriname lies on the Atlantic transform margin of South America located between Guyana and French Guyana. The deep water basin is subdivided by the Demerara high, a platform area which separates the Suriname deep water basin from the French Guyana Basin where the recent Zaedyus oil discovery was made in Late Cretaceous sandstones in a stratigraphic trap. Block 42 and Block 45 sit in the deep water area west of the Demerara Platform in the center of a thick Cretaceous and Tertiary succession associated with the post rift subsidence of the Atlantic continental margin.

A number of onshore and shelf wells have encountered oil and, as previously noted, the Tambaredjo and Calcutta fields are currently producing. These fields are believed to be sourced from deep water Cretaceous source rocks. Seismic evidence suggests thick Late Cretaceous and Tertiary reservoir systems have been deposited in the deep water area and this stratigraphy may contain stratigraphic and structural trapping geometries analogous to both the Zaedyus and Jubilee discoveries.

During 2012, we completed a 3D seismic data acquisition program which covered approximately 3,900 square kilometers of portions of Block 42 and Block 45 offshore Suriname. In August 2013, we completed a 2D seismic program of approximately 1,400 line kilometers over a portion of Block 42, outside of the existing 3D seismic survey. The processing of these seismic data programs is expected to be completed by mid-2014.

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The initial period for Block 42 offshore Suriname is for four years from its effective date (December 13, 2011). The Block 42 exploration phase may be extended to December 2020 at our election. We are currently in the first exploration period ending on December 12, 2015. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer.

The initial period for Block 45 offshore Suriname is for three years from its effective date (December 13, 2011). The Block 45 exploration phase may be extended to December 2018 at our election. We are currently in the first exploration period ending on December 12, 2014. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer.

We have petroleum contracts covering Block 42 and Block 45 offshore Suriname. In November 2012, we finalized the assignment of a 50% participating interest in Block 42 and Block 45 to Chevron Global Energy Inc. ("Chevron") reducing our original interest from 100%. We retain a 50% participating interest in the blocks and remain the operator for the exploration phase of the petroleum contracts.

We are currently assessing prospectivity on license areas in 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, processing seismic information to assess the prospectivity for these license areas.

**Our Reserves**

The following table sets forth summary information about our estimated proved reserves as of December 31, 2013. See "Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Data (Unaudited)" for additional information.

All of our estimated proved reserves as of December 31, 2013, 2012 and 2011 were associated with our Jubilee Field in Ghana.

**Summary of Oil and Gas Reserves**

Reserves Category	2013 Net Proved Reserves(1)			2012 Net Proved Reserves(1)			2011 Net Proved Reserves(1)		
	Oil,		Total	Oil,		Total	Oil,		Total
	Condensate, Natural	Gas(2)		Condensate, Natural	Gas(2)		Condensate, Natural	Gas(2)	
	NGLs	(Bcf)	(MMBoe)	NGLs	(Bcf)	(MMBoe)	NGLs	(Bcf)	(MMBoe)
Proved developed	36	10	38	32	9	33	23	16	26
Proved undeveloped	9	1	9	10	1	10	25	8	26
Total	45	11	47	42	9	43	47	24	51

(1) Our unitized net interest is based on the 54.36660%/45.63340% 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."

Changes for the year ended December 31, 2013, include an increase of 11 MMBbl of proved reserves as a result of drilling and reservoir performance, which is partially offset by 8 MMBbl of production during 2013. During 2013, approximately 1 MMBbl of proved undeveloped



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reserves from December 31, 2012 converted to proved developed reserves as of December 31, 2013. During the year ended December 31, 2013, we incurred \$116.6 million of capital expenditures related to the Jubilee Field Phase 1A development.

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Changes for the year ended December 31, 2012, include a reclassification of 15 MMBbl of proved undeveloped reserves to proved developed reserves related to the successful remediation efforts in treating the near wellbore productivity issues on certain of the producing wells in the Jubilee Field and continued field developmental drilling through the Phase 1A development of the Jubilee Field. These successful remediation efforts reduced the number of future drilling locations for the Jubilee Field (which included drilling locations related to our proved undeveloped reserves) and, as a result, approximately 5 MMBbl of proved undeveloped reserves from December 31, 2011 converted to proved developed reserves as of December 31, 2012. Additional changes include a decrease of 14 Bcf in proved gas reserves due to a decrease in our estimate of fuel gas which will be utilized for operating the FPSO. As a result of progress on the Phase 1A development, approximately 10 MMBbl of proved undeveloped reserves from December 31, 2011 converted to proved developed reserves as of December 31, 2012. During the year ended December 31, 2012, we incurred \$163.7 million of capital expenditures related to Phase 1A.

Changes for the year ended 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 3 Jubilee Field Unitization") and an increase in the estimated gas reserves to be used 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, 2013. All estimated future net revenues are attributable to projected production from the Jubilee Field in Ghana. If we are unable to resolve issues related to continuous removal of associated natural gas in large quantities from the Jubilee Field, and the production restraints caused thereby, then the field's future net revenues discussed herein will be adversely affected. 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."

	<b>Projected Net Revenues (in millions except \$/Bbl)</b>
Future net revenues	\$ 2,836
 <i>Present value of future net revenues:</i>	
PV-10(1)	\$ 2,237
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)	\$ 2,237
 <hr/>	
Benchmark and differential oil price(\$/Bbl)(3)	\$ 108.76

- (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 based on an average of the first-day-of-the-months throughout 2013 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

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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 are a tax exempted company incorporated pursuant to the laws of Bermuda and as the Company's intermediate subsidiaries positioned between it and the subsidiary that is a signatory to the WCTP and DT PAs continue to be tax exempted companies, we 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 2013 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 \$108.02/Bbl for Dated Brent at December 31, 2013. 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 \$0.74/Bbl premium relative to Dated Brent. This differential is utilized in our reserve estimates. The adjusted price utilized to derive the PV-10 is \$108.76/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. 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.

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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, 2013 are based on costs in effect at December 31, 2013 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the fiscal year ended December 31, 2013, 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, 2013, 2012 and 2011, 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, 2013 and related future net revenues and PV-10 at December 31, 2013 are taken from reports prepared by NSAI, 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, 2013 reserve report was completed on January 15, 2014, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2013, 2012 and 2011 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, 2013, based upon its evaluation. NSAI's primary economic assumptions in estimates included an ability to sell oil at a price of \$108.76/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.

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*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 internal reserve and resource estimates. 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 or geology. 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.

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The Audit Committee provides oversight on the processes utilized in the development of our internal reserve and resource estimates on an annual basis. In addition, our technical services 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 review reserves and resource estimates on an annual basis.

#### *License Areas*

The following table sets forth certain information regarding the developed and undeveloped portions of our license areas as of December 31, 2013 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)					
<b>Ghana</b>						
Jubilee Unit	27.1	6.5			27.1	6.5
West Cape Three Points(2)			113.1	35.0	113.1	35.0
Deepwater Tano			137.8	24.8	137.8	24.8
<b>Ireland</b>						
FEL 1/13			259.9	194.9	259.9	194.9
FEL 2/13			189.8	161.3	189.8	161.3
FEL 3/13			193.2	164.2	193.2	164.2
<b>Mauritania</b>						
Block C8			2,940.6	2,646.5	2,940.6	2,646.5
Block C12			1,748.3	1,573.4	1,748.3	1,573.4
Block C13			1,927.4	1,734.7	1,927.4	1,734.7
<b>Morocco(3)</b>						
Cap Boujdour			7,349.1	5,511.8	7,349.1	5,511.8
Essaouira			2,898.7	2,174.1	2,898.7	2,174.1
Foum Assaka			1,199.7	674.8	1,199.7	674.8
Tarhazoute(4)			1,915.9	1,436.9	1,915.9	1,436.9
<b>Suriname</b>						
Block 42			1,526.1	763.1	1,526.1	763.1
Block 45			1,266.7	633.3	1,266.7	633.3
<b>Total</b>	<b>27.1</b>	<b>6.5</b>	<b>23,666.3</b>	<b>17,728.8</b>	<b>23,693.4</b>	<b>17,735.1</b>

- 
- (1) Net acreage based on Kosmos' participating interest, before the exercise of any options or back-in rights. Our net acreage in Ghana 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 subject 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. The WCTP "Undeveloped Area" reflected in the table above represents acreage within three discovery areas (Teak, Akasa and Mahogany) that were not subject to relinquishment on the expiry of the exploration phase.
- (3) We have entered into farm-out agreements covering our four license areas in Morocco. The net acres shown do not reflect these farm-outs, as the agreements were not closed as of December 31, 2013. Once these farm-out agreements become effective, our

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estimated net acres in the Cap Boujdour, Essaouira, Foug Assaka and Tarhazoute license areas is 4,042.0 thousand acres, 869.6 thousand acres, 359.0 thousand acres and 574.8 thousand acres, respectively.

(4)

In October 2013, Kosmos executed a petroleum agreement with the ONHYM, the national oil company of the Kingdom of Morocco, covering the Tarhazoute Offshore block, to which the Company previously held certain exploration rights under a 2011 reconnaissance contract. Under

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the terms of the petroleum contract, the Company is the operator of the Tarhazoute Offshore block. ONHYM holds a 25% carried interest in the block through the exploration period. We are currently in the first exploration period, which is for two and one-half years from its effective date (December 9, 2013) ending in June 2016. The exploration phase may be extended for a total duration of eight years at our election and subject to our fulfilling specific work obligations, which include acquisition of 3D seismic data during the first period and drilling an exploration well in each of the subsequent periods. In the event of commercial success, the Company has the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation concession from the Government of Morocco, which may be extended for an additional period of 10 years under certain circumstances. The petroleum contract is subject to customary government approvals.

### *Drilling activity*

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

	Exploratory and Appraisal Wells(1)						Development Wells(1)							
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total		Total	Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<b>Year Ended</b>														
<b>December 31, 2013</b>														
<i>Ghana</i>														
Jubilee Unit							2	0.48			2	0.48	2	0.48
Deepwater Tano			1	0.18	1	0.18							1	0.18
<i>Cameroon</i>														
N'dian River			1	1.00	1	1.00							1	1.00
<b>Total</b>			2	1.18	2	1.18	2	0.48			2	0.48	4	1.66
<b>Year Ended</b>														
<b>December 31, 2012</b>														
<i>Ghana</i>														
Jubilee Unit							5	1.20			5	1.20	5	1.20
West Cape Three Points			1	0.31	1	0.31							1	0.31
Deepwater Tano			1	0.18	1	0.18							1	0.18
<b>Total</b>			2	0.49	2	0.49	5	1.20			5	1.20	7	1.69
<b>Year Ended</b>														
<b>December 31, 2011</b>														
<i>Ghana</i>														
Jubilee Unit							1	0.24			1	0.24	1	0.24
West Cape Three Points			4	1.24	4	1.24							4	1.24
<i>Cameroon</i>														
Kombe-N'sepe			1	0.35	1	0.35							1	0.35
<b>Total</b>			5	1.59	5	1.59	1	0.24			1	0.24	6	1.83

(1)

As of December 31, 2013, 10 exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. Thirteen development wells awaiting completion have also been excluded. These wells are shown as "Wells Suspended or Waiting on Completion" in the table below.



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- (2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.
- (3) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be a productive well, as opposed to the year the well was drilled.

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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, 2013.

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<b>Ghana</b>								
Jubilee Unit								
West Cape Three Points					9	2.78		
TEN			1	0.17			13	2.21
Deepwater Tano					1	0.18		
<b>Total</b>			1	0.17	10	2.96	13	2.21

### *Undeveloped license area expirations*

The WCTP PA has a duration of 30 years from its effective date (July 2004); however, in July 22, 2011, at the end of the seven-year exploration phase, the WCTP Relinquishment Area was relinquished. We maintain rights to our three existing discoveries within the WCTP Block (Akasa, Mahogany and Teak) as the WCTP PA remains in effect after the end of the exploration phase. Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished. 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, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights to negotiate extends 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 exploration phase of the DT PA expired in January 2013. Our existing Wawa discovery within the DT Block was 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. Evaluation and appraisal activities continue on the Wawa discovery. Additionally, the TEN development project was not subject to relinquishment. We and our DT Block partners exercised 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.

During 2013, we took all actions required to voluntarily relinquish all of the area under the Ndian River Block and Fako Block in Cameroon.

### *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

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manner may hinder our access to oil and natural gas markets or delay our oil and natural gas production."

**Significant License Agreements**

Below is a discussion concerning the licenses governing our current drilling and production operations.

***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. As a result of farm-out agreements and other sales of partners' interests for the WCTP Block, Kosmos, Anadarko WCTP Company ("Anadarko"), Tullow and Sabre Oil and Gas Limited ("Sabre"), a wholly owned subsidiary of Petro S.A., 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. GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block of 2.5%. 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. 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 PA has a duration of 30 years from its effective date (July 2004); however, in July 22, 2011, at the end of the seven-year exploration phase, the WCTP Relinquishment Area was relinquished. We maintain rights to our three existing discoveries within the WCTP Block (Akasa, Mahogany and Teak) as the WCTP PA remains in effect after the end of the exploration phase. Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished. 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, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights to negotiate 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. As a result of farm-out agreements and other sales of partners interests for the DT Block, Kosmos, Anadarko, Tullow and Sabre's participating interests are

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18%, 18%, 49.95% and 4.05%, respectively. Tullow is the operator. GNPC has a 10% participating interest and will be carried through the exploration and development phases. GNPC has the option to acquire additional paying interests in a commercial discovery on the DT Block of 5%. 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. 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 exploration phase of the DT PA expired in January 2013 and all work and financial obligations for the exploration periods under the DT PA have been met. Our existing Wawa discovery within the DT Block was 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. Evaluation and appraisal activities continue on the Wawa discovery. Additionally, the TEN development project was not subject to relinquishment. We and our DT Block partners exercised 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.

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. A Pre Unit Agreement was agreed to between the contractors groups of the WCTP and DT Blocks in 2008, with a more comprehensive unit agreement, the UUOA, agreed to in 2009 which govern each party's respective rights and duties in the Jubilee Unit. 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 in accordance with 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 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 4 Joint Interest Billings")

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to 24.07710%. The accounting for the Jubilee Unit is in accordance with the redetermined tract participation stated. Although the Jubilee Field is unitized, Kosmos' participating 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.

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. We 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. Our responsibilities also extended to project management of the design and implementation of the complete field development system. The Unit Operator is responsible for drilling and completing the development wells for the Jubilee Field 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 and subsequent phases. 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.

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 submitted the JFFDP to Ghana's Minister of Energy in December 2012 and subsequently withdrew based on discussions with the government of Ghana. A PoD providing for the next development of reservoirs within the Jubilee Field is expected to be submitted during 2014, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all.

***Morocco Exploration Agreements***

Effective September 1, 2011, we entered into the Cap Boujdour Offshore Petroleum Agreement as the operator. In October 2013, we entered into a farm-out agreement with Cairn, covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at \$25.0 million and one exploration well capped at \$100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at \$100.0 million per well. Additionally, Cairn will contribute \$12.3 million towards our future costs and, upon completion of the transaction, \$0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator. The Moroccan national oil company, ONHYM, has a carried 25% participating interest. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production, if any. The Cap Boujdour Offshore block comprises approximately 7.35 million acres (29,741 square kilometers) (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 Sahrawi Arab Democratic Republic.") The exploration term of the Cap Boujdour Offshore Permits, beginning on September 5, 2011, is eight years and includes an initial exploration period of one year and six months, which was extended for one year to March 5, 2014,

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followed by the first extension period of two years and the second extension period of four years and six months. We recently gave notice to enter the first extension period to be effective March 5, 2014. By entering the first extension period we are obligated to drill one exploration well. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Effective July 1, 2011, we entered into the Foug Assaka Offshore Petroleum Agreement as operator. In August 2013, final government approvals and processes were completed for the acquisition of an additional 18.75% participating interest in the Foug Assaka block in the Agadir Basin offshore Morocco from Pathfinder, a wholly owned subsidiary of Fastnet, one of our block partners. Pathfinder has retained an 18.75% participating interest. The Moroccan national oil company, ONHYM, has a 25% carried participating interest and is carried by us and Pathfinder proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production. The term of the Foug Assaka Offshore Permits, beginning on July 1, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of two years and six months and the second extension period of three years. We recently entered the first extension period effective January 1, 2014. By entering the first extension period we are obligated to drill one exploration well. After the required relinquishment of acreage to enter the first extension period, the Foug Assaka Offshore block comprises approximately 1.2 million acres (4,855 square kilometers). In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Effective April 2, 2012, we entered into the Essaouira Offshore Petroleum Agreement as operator. In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013 and our participating interest in the Essaouira Offshore block is 75%. The Moroccan national oil company, ONHYM, has a 25% carried participating interest and is carried by the block partners proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production. The Essaouira Offshore Block comprises approximately 2.9 million acres (11,731 square kilometers). The term of the Essaouira Offshore Permits, beginning November 8, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of three years and the second extension period of two years and six months. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances. In late 2011 and early 2012, we acquired approximately 2,363 square kilometers of 3D seismic data in Essaouira Offshore block and processing is ongoing.

Effective December 6, 2013, we entered into the Tarhazoute Offshore Petroleum Agreement as operator with a 75% participating interest. The Moroccan national oil company, ONHYM, has a 25% carried participating interest and is carried by Kosmos. We are required to pay a 10% royalty on oil

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produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production. The Tarhazoute Offshore block comprises approximately 1.9 million acres (7,753 square kilometers). The exploration term of the Tarhazoute Offshore Permits, beginning December 9, 2013, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of two years and six months and the second extension period of three years. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In October 2013, we entered into three farm-out agreements with BP covering our three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Fom Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of \$120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of \$120.0 million per well. Upon close of the transaction, BP shall also pay \$36.3 million for their share of past costs and \$8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Fom Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

*Suriname Exploration Agreements*

On December 13, 2011, we signed a petroleum contract covering Offshore Block 42 located offshore Suriname. We have a 50% participating interest in the block and are the operator. Staatsolie Maatschappij Suriname N.V. ("Staatsolie"), Suriname's national oil company, has the option to back into the contract with an interest of not more than 10% upon approval of a development plan. The Block 42 petroleum contract provides for us to recover our share of expenses incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 80% of gross production prior to profit oil being split between the government of Suriname 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 36% is applied to profits. The initial period of the exploration phase is four years and there are two renewal periods consisting of three years for the first renewal period and two years for the second renewal period. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer. Block 42 comprises approximately 1.5 million acres (approximately 6,176 square kilometers). In November 2012, Kosmos closed an agreement with Chevron under which Kosmos assigned half of its interest in Block 42, offshore Suriname, to Chevron. Each party now has a 50% participating interest in Block 42.

On December 13, 2011, we signed a petroleum contract covering Offshore Block 45 located offshore Suriname. We have a 50% participating interest in the block and are the operator. Staatsolie, Suriname's national oil company, will be carried through the exploration and appraisal phases and has the option to back into the contract with an interest of not more than 15% upon approval of a development plan. The Block 45 petroleum contract provides for us to recover our share of expenses

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incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 80% of gross production prior to profit oil being split between the government of Suriname 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 36% is applied to profits. The initial period of the exploration phase is three years and there are two renewal periods consisting of two years each. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer. Block 45 comprises approximately 1.3 million acres (approximately 5,126 square kilometers). In November 2012, Kosmos closed an agreement with Chevron under which Kosmos assigned half of its interest in Block 45, offshore Suriname, to Chevron. Each party now has a 50% participating interest in Block 45.

In October 2012, we completed a 3D seismic data acquisition program which covered approximately 3,900 square kilometers of portions of Block 42 and Block 45, both in the Suriname-Guyana Basin. Processing of the data is ongoing.

***Mauritania Exploration Agreements***

Effective June 15, 2012, we entered into three petroleum contracts covering offshore Mauritania blocks C8, C12 and C13 with the Islamic Republic of Mauritania. We have a 90% participating interest and are the operator. The Mauritanian national oil company, Société Mauritanienne des Hydrocarbures ("SMH") now called Société Mauritanienne des Hydrocarbures et de Patrimoine Minier ("SMHPM"), currently has a 10% carried participating interest during the exploration period only. Should a commercial discovery be made, SMHPM's 10% carried interest is extinguished and SMHPM will have an option to acquire a participating interest of 10% to 14%. SMHPM's interest in a commercial development will not be carried as to appraisal and development costs. Cost recovery oil is apportioned to Kosmos from up to 55% of total production prior to profit oil being split between the government of Mauritania and the contractor. Profit oil is then apportioned based upon "R-factor" tranches, where the R-factor is cumulative net revenues divided by the cumulative investment. We are required to pay a royalty of 7%. These royalties are to be paid in-kind or, at the election of the government of Mauritania, in cash. A corporate tax rate of 27% is applied to profits at the license level. The Blocks C8, C12 and C13 currently comprise approximately 2.9 million acres (11,900 square kilometers), 1.7 million acres (7,075 square kilometers) and 1.9 million acres (7,800 square kilometers) respectively. The terms of exploration periods of these Offshore Blocks are all ten years and include an initial exploration period of four years followed by the first extension period of three years and the second extension period of three years. Kosmos is currently in the first exploration period of the blocks, expiring in June 2016. In the event of commercial success, we have the right to develop and produce oil for 25 years and gas for 30 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

***Ireland Exploration Agreements***

Effective April 17, 2013, we entered into three farm-in agreements, whereby we have an 85% participating interest in Frontier Exploration License 2/13 and 3/13, and a 75% participating interest in Frontier Exploration License 1/13, all part of the Porcupine Basin, offshore Ireland. We are the operator of the three blocks. We completed 3D seismic acquisition over the blocks and processing of the data is underway.

In Frontier Exploration License 2/13 and 3/13, Europa has a 15% participating interest in the areas. Each License comprises approximately 0.2 million acres (700 square kilometers). In addition to the fully funded 3D seismic acquisition, we will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap. The per-well investment cap for the first well is



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\$90.0 million on Frontier Exploration License 2/13 and \$110.0 million on Frontier Exploration License 3/13.

In Frontier Exploration License 1/13, Antrim has a 25% participating interest in the area. The License comprises approximately 0.3 million acres (1,000 square kilometers). We have fully funded the 3D seismic program on the block.

We are required to pay a corporate income tax rate of 25% and potentially a petroleum resource rent tax of between 0% and 15% as determined by a profitability-based sliding scale.

**Sales and Marketing**

Production from the Jubilee Field began in November 2010, and we received our first oil revenues in early 2011. As provided under 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. 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 staff that are substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and natural gas assets, or to evaluate, bid for and purchase a greater number of licenses 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 our stakeholders that we will be able to successfully compete when attempting to make further strategic acquisitions.

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**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 Sahrawi 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 commence;

enjoin some or all of the operations or facilities deemed not in compliance with permits;

restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;

limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and

require remedial measures to mitigate or remediate pollution, including pollution resulting 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 increase costs to the oil and gas industry in general, such as more stringent or costly waste handling, disposal or cleanup requirements or financial responsibility and assurance requirements.

For example, the Macondo spill in the Gulf of Mexico in 2010 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

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this or similar incidents, which could materially delay, restrict or prevent our operations in those countries.

***Capping and Containment***

We entered into an agreement with a third party service provider to supply subsea capping and containment equipment on a global basis. The equipment includes capping stacks, debris removal, subsea dispersant and auxiliary equipment. The equipment meets industry accepted standards and can be deployed by air cargo and other conventional means to suit multiple application scenarios. We also developed an emergency response plan and response organization to prepare and demonstrate the Company's readiness to respond to a subsea well control incident.

***Oil Spill Response***

To complement our agreement discussed above for subsea capping and containment equipment, we became a charter member of the Global Dispersant Stockpile. The new dispersant stockpile, which is managed by Oil Spill Response Limited ("OSRL") of Southampton, United Kingdom ("UK"), an oil spill response contractor, consists of 5,000 cubic meters of dispersant strategically located at OSRL bases around the world. The total volume of the stockpile located at OSRL bases around the world is approximate to the amount used in the Macondo response.

***Ghana***

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 OSCP, 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. More than 200 personnel (composed primarily of Tullow and Kosmos employees, Ghanaian Navy, Ghana EPA, Maritime Authority, Petroleum Commission, Ports and Harbor personnel, local contractors and community representatives) 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 would engage the services of OSRL.

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 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 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,

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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, 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 respond in a timely manner as intended, perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons.

*Morocco*

We recently developed an Oil Spill Contingency Plan to support our drilling operations. The plan calls for the addition of Tier 1 spill equipment to our shorebase in Agadir, Morocco to respond to a harbor or shoreline incident in the area. We will have access to additional Tier 2 and Tier 3 equipment from the Southampton, UK location.

Per common industry practice, under the agreements currently in place, or agreements we may enter into during the future, 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 participating 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. We maintain, or expect to maintain, upon commencement of drilling operations, insurance coverage typical of the industry in the areas we operate in; these include property damage insurance, loss of production insurance, wreck removal insurance, control of well insurance, general liability including pollution liability to cover pollution from wells and other operations. We also participate in an insurance coverage program for the Jubilee FPSO. Our insurance is, or will be, carried in amounts typical for the industry and relative to our size and operations and in accordance with our contractual and regulatory obligations.

**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 association with local or foreign contractors. 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 executive capacity. The Petroleum Commission is the regulatory body for the upstream petroleum industry and the advisor to the Ministry of Energy. GNPC has rights to undertake petroleum operations in any

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acreage declared open by Ghana's Ministry of Energy. As well, when petroleum operations are undertaken by GNPC in association with contracts, GNPC has a carried interest in each petroleum agreement and, following the declaration of any commercial discovery, such carried interest is typically subject to increase by a certain agreed upon amount at the option of GNPC. 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 Exploration and Production Act 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 Exploration and Production Act 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 of 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 appraisal plans, 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 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." The Petroleum (Local Content and Local Participation in Petroleum Activities) Regulations comes into effect in February 2014. The Regulations mandate certain levels of local participation in service companies, in-country manufacturing of goods and the provision of services, and certain reporting requirements.

***Ireland***

The primary legislative acts relevant to our operations in the Republic of Ireland are: (1) The Petroleum and Other Minerals Development Act, 1960 (the "Irish Petroleum Act") and (2) the Gas Act, 1960. The Ministry of Communications, Energy and Natural Resources is the regulatory authority tasked with maximizing the benefits to the Irish State from exploration for and production of indigenous oil and gas resources. The Irish Petroleum Act vests all State petroleum in the Minister. Only the Minister, licensees under an exploration license, a petroleum prospecting license, or a reserved area license, and lessees under a valid petroleum lease may search for petroleum. The Ministry enters into petroleum agreements (licenses for exploration and leases for development and production) on behalf of the State. Assignments of interests in licenses also require the consent of The Ministry. The relevant tax law is the Taxes Consolidation Act, 1997, as amended by the Finance Act, 1999. The current license and lease terms are found in the Licensing Terms for Offshore Oil and Gas Exploration, Development & Production, 2007.

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***Mauritania***

The main legislative acts in the Islamic Republic of Mauritania relevant to petroleum exploration and production are Law No. 2010-033 dated July 20, 2010 and its amendment (the "Hydrocarbon Laws"). The regulatory authority in Mauritania is the Ministry of Petroleum, Energy and Mines and the national oil company acting on its behalf is SMHPM. SMHPM was instituted by Decree No. 2005-106 of November 7, 2005 and modified by Decree No. 2009-168 of May 3, 2009 and Decree No. 2014-01. Pursuant to the Hydrocarbon Laws, Mauritania or SMHPM may undertake petroleum operations and may authorize other legal entities to undertake petroleum operations under exploration-production contracts. The Ministry shall sign petroleum contracts on behalf of Mauritania. Assignments of interests in petroleum contracts also require the consent of The Ministry. The exploration period shall not be more than ten years, subject to certain permitted extensions and the exploitation period shall not be more than 25 years. Petroleum contracts may provide that Mauritania has a carried interest of up to 10% during the exploration period. Petroleum contracts shall grant Mauritania the option to participate for a percentage not less than 10% in the rights of the contractor during the exploitation period.

***Morocco***

The two main legislative acts in Morocco relevant to petroleum exploration and production are (i) the Law 21-90 (April 1, 1992) as amended and completed by the Law 27-99 (February 15, 2000) and (ii) the Decree 2-93-786 (November 3, 1993) as amended and completed by decree 2-99-210 (March 16, 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 ONHYM. ONHYM is a public establishment (*établissement public*) with the legal personality and financial autonomy created pursuant to the Law 33-01 (November 11, 2003) which was further completed by the Decree 2-04-372 (December 29, 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 contract 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 interests in exploration permits 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 block 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 was founded in 1980 as a state enterprise and holds mining rights onshore and offshore in

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Suriname. The Suriname 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. Assignments of interests in petroleum contracts also require the consent of Staatsolie and/or 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, 2013, we had approximately 250 employees. None of these employees are 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 in March 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.

**Available Information**

Kosmos is listed on the NYSE and our common shares are 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.

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

**Item 1A. Risk Factors**

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

**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. A portion of our oil and natural gas assets consists of discoveries without approved PoDs and with limited well penetrations, as well as identified yet unproven prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. However, the areas we decide to drill may not yield oil or natural gas in commercial quantities or quality, or at all. Many of our current discoveries and all of our prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Accordingly, we do not know if any of our discoveries or prospects will contain oil or natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil or natural gas is found on our discoveries or prospects in commercial quantities, construction costs of gathering lines, subsea infrastructure and floating production systems and transportation costs (or analogous developmental costs associated with onshore production in the case of our onshore licenses) 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 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 deepwater offshore Morocco, Suriname, Mauritania and Ireland licenses have not yet proved to be economically viable production areas, as to date we do not have a commercially viable discovery or production in



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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 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 addition, a successful discovery would require significant capital expenditure in order to develop and produce oil, even if we deemed such discovery to be commercially viable. See " Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms or at all in the future, which may in turn limit our ability to develop our exploration, appraisal, development and production activities." In the areas in which we operate, we face higher above-ground risks necessitating higher expected returns, the requirement for increased capital expenditures due to a general lack of infrastructure and underdeveloped oil and gas industries, and increased transportation expenses due to geographic remoteness, which either require a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. See " Our operations may be adversely affected by political and economic circumstances in the countries in which we operate." Furthermore, if our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and could be forced to modify our plan of operation.

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***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.

We are currently in the initial exploration phase for our petroleum contracts in Mauritania, with such phases of the Offshore Blocks C8, C12 and C13 expiring in June 2016. Under these petroleum contracts, we have work commitments to perform exploration and other related activities. Failure to do so may result in our loss of the licenses.

We are currently in the initial exploration phase for our petroleum contract in Cap Boujdour Offshore block, Western Sahara, and have provided notice to enter the first extension period commencing March 5, 2014 and expiring March 5, 2016. Also in Morocco, we are currently in the initial exploration phase of the Essaouira Offshore block (expiring May 8, 2014) and the Tarhazoute Offshore block (the Tarhazoute Petroleum Agreement effective on December 6, 2013, however, permits have not yet been issued to establish term of the initial exploration phase). Additionally, we are currently in the first extension period for the Foum Assaka Offshore block in Morocco expiring on July 1, 2016. Under these petroleum contracts, we have work commitments to perform exploration and other related activities. Failure to do so may result in our loss of the 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 seismic; acquire, process and interpret seismic data; 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

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exploration phase to conduct certain studies and reprocess seismic data. Failure to complete such requirements may result in our loss of these licenses.

We are currently in the initial exploration phases under our Frontier Exploration Licenses 1-13, 2-13, and 3-13 offshore Ireland. Under these petroleum contracts, we have work commitments to perform exploration and other related activities. Failure to do so may result in our loss of the license.

The exploration phase of the WCTP and DT PAs have expired. Pursuant to the terms of such PAs, while we and our respective block partners have certain rights to negotiate new petroleum agreements with respect to the WCTP Relinquishment Area and the DT Relinquishment Area, we cannot assure you that we will determine to enter any such new petroleum agreements. 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 Operations by Geographic Area."

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

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or unit partners. If any of our partners in the blocks or unit in which we hold interests are unable to fund their share of the exploration and development expenses, we may be liable for such costs. In the past, certain of our 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 counterparties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Joint interest receivables arise from our block partners. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

***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%. An additional

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redetermination could occur sometime 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, or the scope, of exploration or development activities or the amount of capital expenditures and, therefore, may not be able to carry out one of our key business strategies of minimizing the cycle time between discovery and initial production. The success and timing of exploration and development activities 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.

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

The process of estimating oil and natural gas reserves is technically complex. It requires interpretations of available technical data and many assumptions, including those relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Item 1. Business Our Reserves" for information about our estimated oil and natural gas reserves and the present value of our net revenues at a 10% discount rate ("PV-10") and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2013.

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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 PV-10 and the Standardized Measure as of December 31, 2013 would each decrease by approximately \$21.5 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,

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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 may need to raise substantial additional capital through additional debt financing, strategic alliances or future private or public equity offerings if our cash flows from operations, or the timing of, are not sufficient to cover such costs.

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

the scope, rate of progress and cost of our exploration, appraisal, development and production activities;

the success of our exploration, appraisal, development and production activities;

oil and natural gas prices;

our ability to locate and acquire hydrocarbon reserves;

our ability to produce oil or natural gas from those reserves;

the terms and timing of any drilling and other production-related arrangements that we may enter into;

the cost and timing of governmental approvals and/or concessions; and

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

Assuming we are able to commence exploration, appraisal, development and production activities or successfully exploit our licenses during the exploratory term, our interests in our licenses (or the development/production area of such licenses as they existed at that time, as applicable) could extend beyond 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."



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All of our proved reserves, oil production and cash flows from operations are currently associated with our licenses offshore Ghana. Should any event occur which adversely affects such proved reserves, oil production and cash flows from these licenses, including, without limitation, any event resulting from the risks and uncertainties outlined in this "Risk Factors" section, our business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially and adversely affected.

***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 or man-made 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.



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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 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

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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 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.

In Ghana, we currently produce associated gas from the Jubilee Field. While the Government of Ghana is in the process of constructing a gas pipeline from the Jubilee Field to transport such natural gas for processing and sale, to date the pipeline has not been completed. Further, even if the pipeline was completed, we granted the first 200 BCF of natural gas from the Jubilee Phase 1 to Ghana at no cost. Thus, in Ghana, even if the infrastructure was in place for natural gas processing and sales, it would still be quite some time before we would be able to commercialize our Ghana natural gas.

***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 is in the process of completing the construction and connection of a gas pipeline from the Jubilee Field to transport such natural gas to the mainland for processing and sale; however, to date, the construction of the pipeline and the onshore plant has not been completed and the Company is presently unable to predict with certainty when completion will occur, as several previous completion dates have passed. 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.

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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 remove excess natural gas from the reservoirs' production system via such pipeline or by flaring it. We expect that we will need to flare large quantities of natural gas prior to the completion of the pipeline. However, we have not been issued a permit from the Ghana EPA to flare natural gas produced from the Jubilee Field in substantial quantities. Our petroleum agreements allow the operator to flare gas in certain circumstances to include, without limitation, in circumstances where reinjection is not possible. Ghanaian regulators may claim regulatory uncertainty exists as to whether Ghana EPA or other permits are also needed to conduct such flaring. In the absence of completion of a natural gas pipeline or if we are unable to flare such natural gas for the long-term prior to reaching the Jubilee Field's reinjection capacity, the field's oil production capacity may be adversely affected. Alternatively, if we flare without an amended Ghana EPA permit, we may be subject to regulatory action.

***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, the ability to flare or vent 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 and rates of production may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, climate change, health and safety laws 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.

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***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 pollutants or hazardous materials;

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 or man-made disasters.

These risks are particularly acute in deepwater drilling and exploration. Any of these events could result in loss of human life, significant damage to property, environmental or natural resource damage, impairment, delay or cessation of our operations, lower production rates, adverse publicity, substantial losses and civil or criminal liability. 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, as well as mechanical and technical issues. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

***Our offshore and deepwater operations 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 loss of production, significant liabilities, cost overruns or delays.



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For example, during 2013, we experienced mechanical issues in the Jubilee Field, including failures of our water injection facilities on the FPSO and water and gas injection wells. This equipment downtime negatively impacted oil production during the year. 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, South America and Europe 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, the DT PA and the UUOA cover the two blocks and the Jubilee Unit that form the basis of our current 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, assertions that could be read to give rise to taxes payable under the Ghanaian Tax Law in connection with our IPO, failure to approve PoDs relating to certain discoveries offshore Ghana and the relinquishment of certain exploration areas on our licensed blocks offshore Ghana. These past disagreements have been resolved. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the government of Ghana.

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, South America and Europe 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, South America and Europe. Some or all of these licenses could be affected should either region experience any of the following factors (among others):

severe weather, natural or man-made disasters or acts of God;

delays or decreases in production, the availability of equipment, facilities, personnel or services;

delays or decreases in the availability of capacity to transport, gather or process production; and/or

military conflicts or civil unrest.

For example, oil and natural gas operations in our license areas in Africa and South America 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

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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 a majority of our activities, as it is the case in Ghana, where the Ghanaian Revenue Authority (the "GRA") has disputed certain tax deductions we have claimed in our Ghanaian tax returns covering the past seven fiscal years as non-allowable under the terms of the Ghanaian Petroleum Income Tax Law, as well as non-payment of certain transactional taxes.

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

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

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

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***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 Sahrawi 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 55% participating interest in the Cap Boujdour Offshore block located geographically offshore Western Sahara. Our license was 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.



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

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

***Participants in the oil and gas industry are subject to numerous laws 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 those related to remediation, investigation or permitting.

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

For example, Ghana's Parliament has enacted the Petroleum Revenue Management Act 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 effect on our business. We also cannot assure you that government approval will not be needed for direct or indirect transfers of our petroleum

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agreements or interests thereunder based on existing legislation. See "Item 1. Business Other Regulation of the Oil and Gas Industry Ghana."

The SEC promulgated final rules under the Dodd-Frank Act requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to disclose payments (including taxes, royalties, fees and other amounts) made by such companies or an entity controlled by such companies to the United States or to any non-U.S. government for the purpose of commercial development of oil, natural gas or minerals. The final rules do not contain an exception that would allow companies to exclude payments which may not be disclosed pursuant to foreign laws or confidentiality agreements. However, in July 2013, the United States District Court for the District of Columbia vacated the final rules and the SEC has not as yet proposed revised rules implementing the applicable section of the Dodd-Frank Act. There can be no assurance that we will be able to comply with these regulations, once promulgated, without creating disagreements with these partners or governments. Further, such regulations may place us at a disadvantage to our non-U.S. competitors in doing business in the international oil and gas industry. Any of these consequences could have a material adverse effect on our financial condition and our 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, transportation and disposal 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 and health and safety laws and regulations to which we are subject, and there is a risk such requirements could change in the future or become more stringent. If we violate or fail to comply with such requirements, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain, maintain or renew permits in a timely manner or at all (due to opposition from partners, community or environmental interest groups, governmental delays or 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, maintain or renew permits or such changes in or enactment of laws or regulations could impede or affect our operations, which could have a material adverse effect on our results of operations and financial condition.

We, as an interest owner or as the designated operator of certain of our past, current and future 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, predecessors or other operators. To the extent we do not address these costs and liabilities or if we do not otherwise satisfy our obligations, our operations could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform services related to our operations. There is a risk that we may contract with third parties with unsatisfactory 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.

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

In addition, we expect continued and increasing attention to climate change issues. Various countries and regions, including Ghana, Ireland, Mauritania, Morocco and Suriname, have agreed to reduce emissions of greenhouse gases ("GHGs"), including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion) under the Kyoto Protocol. While the Kyoto Protocol was set to expire in 2012, it has been extended by amendment until 2020 with the understanding among the parties that a new climate change regime will be negotiated by 2015 and succeed the Kyoto Protocol in 2020. Ireland is also a party to the European Union Emissions Trading Scheme that seeks, among other things, to meet the European Union's commitments under the Kyoto Protocol through a "cap and trade" GHG emissions framework. The increased regulation of GHGs by any of the areas in which we, our customers and the end-users of our products operate may increase our compliance costs, such as for monitoring, sequestering 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. The physical impacts of climate change in the areas in which our assets are located or in which we otherwise operate, including through increased severity and frequency of storms, floods and other weather events, could adversely impact our operations or disrupt transportation or other process-related services provided by our third-party contractors.

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 for FCPA violations committed by companies in which we invest in (for example, by way of acquiring

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equity interests in, participating as a joint venture partner with, acquiring the assets of, or entering into certain commercial transactions with) or that we acquire.

***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 and actual prices received in the derivative instrument.

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 and revolving credit facility both contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.***

Our commercial debt facility, and revolving credit facility include certain covenants that, among other things, restrict:

our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;

our incurrence of additional indebtedness;

the granting of liens, other than liens created pursuant to the commercial debt facility and revolving credit 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;



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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, and revolving credit facility.

Our commercial debt facility, and revolving credit facility require us to maintain certain financial ratios, such as debt service coverage ratios and cash flow coverage ratios. All of these restrictive covenants may limit our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility, and revolving credit 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, and revolving credit 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 and revolving credit 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 and, revolving credit 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.***

At December 31, 2013, we had \$900.0 million outstanding and \$600.0 million of committed undrawn capacity under our commercial debt facility, of which \$309.5 million was available. As of December 31, 2013, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability was \$300.0 million. As of December 31, 2013, there were six outstanding letters of credit totaling \$42.0 million under the letter of credit facility agreement. 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.



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

***We 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.



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***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.

***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. In the past, legislation has been introduced in the Congress of the United States that would reform the U.S. tax laws as they apply to certain non-U.S. entities and operations, including legislation that would

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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 similar legislation is passed that 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 who ordinarily reside 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, and its implementing regulations, 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 and interest rate 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 Dodd-Frank Act was signed into law by the President on July 21, 2010. Many of the provisions of the Dodd-Frank Act require implementing regulations by agencies including the Commodity Futures Trading Commission (the "CFTC") and the SEC. The adopting and implementation of these regulations is underway but has not yet been completed.

Of particular importance to us, the CFTC has the authority to, under certain findings, establish position limits for certain futures, options on futures and swap contracts. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC adopted final position limit rules for 28 physical commodity contracts and related futures, options on futures and swaps on November 18, 2011, but these rules were vacated by the United States District Court for Columbia on September 28, 2012 after a lawsuit was brought by market participants. The CFTC has authorized an appeal, and it is unclear when these rules or similar rules might come into effect. Depending on the final form of any such rules, they may affect our ability to cost-effectively hedge our commodity risks.

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. While there are likely to be exceptions from many of these requirements for commercial end users of derivatives like us, the final contours of many of these exceptions, and whether we choose to use them,

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is uncertain at this time. The Dodd-Frank Act and its implementing regulations may also require the counterparties to our derivative instruments to register with the CFTC and become subject to substantial regulation or even spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. These requirements and others could significantly increase the cost of derivatives contracts (including through requirements to clear swaps and to post collateral, each of 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. Our revenues could also be adversely affected if a consequence of the legislation and regulations is to lower commodity prices.

***We may 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. We are vigorously defending 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.

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**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 or sale of any additional securities of ours;

investor perception of our company and of the industry in which we compete; and

general economic, political and market conditions.

*A substantial portion of our total issued and outstanding common 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 (unless they have been sold pursuant to Rule 144 to date). Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rule 144 or Rule 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates and other limitations under Rule 144. Additionally, we have registered all our 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.

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***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 63% 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, 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 conduct annual self-assessments for these committees, currently, only our audit committee is composed entirely of independent directors. 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

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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. Some of our directors are not residents 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

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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.



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**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 15 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. This lawsuit has been removed from the Dallas County State court in which it was originally filed to the United States Federal District Court for the Northern District of Texas, Dallas Division and has been consolidated along with three substantially similar lawsuits into one lawsuit. Additionally, Warburg Pincus LLC and Blackstone Capital Partners were subsequently dismissed as defendants from these lawsuits. 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 Disclosures**

Not applicable.

Table of Contents**PART II****Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***Common Shares Trading Summary*

Our 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.

	2013		2012	
	High	Low	High	Low
First Quarter	\$ 13.05	\$ 10.15	\$ 15.13	\$ 12.30
Second Quarter	12.17	10.09	13.70	10.03
Third Quarter	11.15	9.71	11.75	8.19
Fourth Quarter	11.42	10.03	12.65	9.55

As of February 18, 2014, 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 212. On February 18, 2014, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was \$10.66 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 the Facility and the Corporate Revolver 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. Currently we 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 aggregate of 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 2013, we used net proceeds to repay indebtedness under our Facility and for exploration activities and general corporate purposes. Pending use of the remaining net proceeds, we have invested these net proceeds in institutionally-managed accounts that consist of highly rated investment funds.

Table of Contents*Issuer Purchases of Equity Securities*

Under the terms of our Long Term Incentive Plan ("LTIP"), we have issued shares of restricted shares and restricted share units to our employees. On the date that these restricted shares and restricted share units vest, we provide such employees the option to withhold, via a net exercise provision pursuant to our applicable restricted share award agreements and the LTIP, the number of vested shares (based on the closing price of our common shares on such vesting date) equal to tax liability owed by such grantee. The shares withheld from the grantees to settle their tax liability are reallocated to the number of shares available for issuance under the LTIP. The following table outlines the total number of shares withheld during fiscal year 2013 and the average price paid per share.

	<b>Total Number of Share Withheld/Purchased (In thousands)</b>	<b>Average Price Paid per Share</b>
January 1, 2013 January 31, 2013		\$
February 1, 2013 February 28, 2013		
March 1, 2013 March 31, 2013	6	12.51
April 1, 2013 April 30, 2013	189	10.91
May 1, 2013 May 31, 2013	899	11.52
June 1, 2013 June 30, 2013	12	10.32
July 1, 2013 July 31, 2013		
August 1, 2013 August 31, 2013		
September 1, 2013 September 30, 2013		
October 1, 2013 October 31, 2013	3	10.42
November 1, 2013 November 30, 2013		
December 1, 2013 December 31, 2013		
<b>Total</b>	<b>1,109</b>	<b>11.41</b>

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#### *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, 2013, in cumulative total 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	2012	2013
Kosmos Energy Ltd. (KOS)	\$ 100.00	\$ 68.11	\$ 68.61	\$ 62.11
S&P 500 (SPX)	100.00	94.55	109.36	143.24
SIG Oil Exploration & Production Index (EPX)	100.00	84.33	78.53	99.03

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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, 2013, should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

#### **Consolidated Statements of Operations Information:**

	Years Ended December 31,				
	2013	2012	2011(1)	2010	2009
(In thousands, except per share data)					
<b>Revenues and other income:</b>					
Oil and gas revenue	\$ 851,212	\$ 667,951	\$ 666,912	\$	\$
Interest income	275	1,108	9,093	4,231	985
Other income	941	3,150	775	5,109	9,210
<b>Total revenues and other income</b>	<b>852,428</b>	<b>672,209</b>	<b>676,780</b>	<b>9,340</b>	<b>10,195</b>
<b>Costs and expenses:</b>					
Oil and gas production	96,791	95,109	83,551		
Exploration expenses	230,314	100,652	128,753	73,126	22,127
General and administrative	158,421	157,087	111,235	98,967	55,619
Depletion and depreciation	222,544	185,707	140,469	2,423	1,911
Amortization deferred financing costs	11,054	8,984	16,193	28,827	2,492
Interest expense	36,811	52,207	65,749	59,582	6,774
Derivatives, net	17,027	31,490	11,777	28,319	
Loss on extinguishment of debt		5,342	59,643		
Doubtful accounts expense			(39,782)	39,782	
Other expenses, net	3,512	1,475	149	1,094	46
<b>Total costs and expenses</b>	<b>776,474</b>	<b>638,053</b>	<b>577,737</b>	<b>332,120</b>	<b>88,969</b>
<b>Income (loss) before income taxes</b>	<b>75,954</b>	<b>34,156</b>	<b>99,043</b>	<b>(322,780)</b>	<b>(78,774)</b>
Income tax expense (benefit)	166,998	101,184	76,686	(77,108)	973
<b>Net income (loss)</b>	<b>\$ (91,044)</b>	<b>\$ (67,028)</b>	<b>\$ 22,357</b>	<b>\$ (245,672)</b>	<b>\$ (79,747)</b>
Accretion to redemption value of convertible preferred units			(24,442)	(77,313)	(51,528)
<b>Net loss attributable to common shareholders/unit holders</b>	<b>\$ (91,044)</b>	<b>\$ (67,028)</b>	<b>\$ (2,085)</b>	<b>\$ (322,985)</b>	<b>\$ (131,275)</b>
<b>Net income (loss) per share attributable to common shareholders</b> (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):					
Basic	\$ (0.24)	\$ (0.18)	\$ 0.09		

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Diluted	\$	(0.24)	\$	(0.18)	\$	0.09
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Weighted average number of shares used to compute net income (loss) per share (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):

Basic	376,819	371,847	368,474
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Diluted	376,819	371,847	368,607
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(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

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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)

For the year ended December 31, 2011, we have presented net income (loss) per share attributable to common shareholders (including weighted average number of shares used to compute net income (loss) per share attributable to common shareholders) from the date of our corporate reorganization, May 16, 2011, to December 31, 2011. Net income for the period from May 16, 2011 through December 31, 2011 was \$36.1 million. For the periods presented prior to our corporate reorganization, we do not calculate historical net income (loss) per share attributable to common shareholders because we did not have a common unit of ownership in those periods.

### **Consolidated Balance Sheets Information:**

	As of December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Cash and cash equivalents	\$ 598,108	\$ 515,164	\$ 673,092	\$ 100,415	\$ 139,505
Total current assets	734,961	750,118	1,112,481	559,920	256,728
Total property and equipment, net	1,522,962	1,525,762	1,377,041	998,000	604,007
Total other assets	87,903	90,243	62,412	133,615	161,322
Total assets	2,345,826	2,366,123	2,551,934	1,691,535	1,022,057
Total current liabilities	219,324	190,253	339,607	482,057	139,647
Total long-term liabilities	1,134,167	1,146,964	1,191,601	845,383	287,022
Total convertible preferred units				978,506	813,244
Total shareholders' equity/unit holdings equity	992,335	1,028,906	1,020,726	(614,411)	(217,856)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	2,345,826	2,366,123	2,551,934	1,691,535	1,022,057

### **Consolidated Statements of Cash Flows Information:**

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Net cash provided by (used in):					
Operating activities	\$ 522,404	\$ 371,530	\$ 364,909	\$ (191,800)	\$ (27,591)
Investing activities	(324,133)	(402,662)	(385,140)	(589,975)	(500,393)
Financing activities	(115,327)	(126,796)	592,908	742,685	519,695

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**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 a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margin. Our assets include existing production and other major development projects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Ireland, Mauritania, Morocco (including Western Sahara) and Suriname.

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

**Recent Developments**

*Debt*

Our commercial debt facility ("Facility") provides a revolving-credit and letter of credit facility with a total commitment of \$1.5 billion. The availability period for the revolving-credit facility, as amended in April 2013, expires on December 15, 2014 and the letter of credit sublimit expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on December 15, 2014, outstanding borrowings will also be constrained by an amortization schedule. The first required payment could be as early as March 31, 2015, subject to the level of outstanding borrowings and the borrowing base constraints.

In September 2013, as part of the normal borrowing base determination process, the availability under the Facility was reduced to \$1.2 billion. As of December 31, 2013, borrowings under the Facility totaled \$900.0 million, the undrawn availability under the Facility was \$309.5 million and there were no letters of credit drawn under the facility.

In April 2013, the availability under the Corporate Revolver was increased from \$260.0 million to \$300.0 million by additional commitments from existing and new financial institutions.

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility is \$100.0 million, with additional commitments up to \$50.0 million being available if the existing lender increases its commitments or if commitments from new financial institutions are added. The LC Facility provides that we shall maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%. The fees associated with outstanding letters of credit issued will be 0.5% per annum. The LC Facility has an availability period which expires on June 1, 2016. We may voluntarily cancel any commitments available under the LC Facility at any time. As of December 31, 2013, there were six outstanding letters of credit totaling \$42.0 million under the LC Facility.



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*Rig Agreement*

In June 2013, we signed a long-term rig agreement with a subsidiary of Atwood Oceanics, Inc. for the new build drillship "Atwood Achiever." Currently under construction, the rig is expected to commence drilling operations in the second half of 2014. The rig's capabilities include drilling to total depths of up to 40,000 feet (12,200 meters), and in water depths of up to 12,000 feet (3,660 meters). The rig agreement covers an initial period of three years at a day rate of approximately \$0.6 million, with an option to extend the agreement for an additional three-year term.

*Ghana*

During 2013, we had eight liftings of oil totaling 7,778 MBbl from the Jubilee Field production resulting in revenues of \$851.2 million. Our average realized price was \$109.44 per barrel.

We previously received an approval for the Phase 1A PoD of the Jubilee Field, and production from Phase 1A commenced in late 2012. The Phase 1A program includes the drilling of up to eight additional wells consisting of up to five production wells and three water injection wells. Five wells (three producers and two injectors) are online. Program execution is expected to be completed in 2014.

In January 2013, we relinquished the discovery area associated with the Banda discovery on the WCTP Block, as we do not consider this discovery to be commercially viable. As the exploration phase of the WCTP PA has expired, we no longer have any rights to this discovery area (unless we enter into a new petroleum agreement with the Ghana Ministry of Energy and the Ghana National Petroleum Company covering this and other relinquished areas of the WCTP Block). This relinquishment did not have a material impact on our consolidated financial statements for the year ended December 31, 2013 or 2012, as we previously recorded the unsuccessful well costs associated with the Banda-1 exploration well as exploration expenses in 2011.

The Sapele-1 exploration well on the DT Block was completed in February 2013. The well was not considered a productive well and accordingly was plugged and abandoned.

In May 2013, the government of Ghana approved the PoD over the Tweneboa, Enyenra and Ntomme ("TEN") discoveries. Development of TEN will include the drilling and completion of up to 24 development wells, half of the wells designed as producers and the remainder as water or gas injectors to support ultimate field recoveries. The TEN development is expected to deliver first oil in 2016. Future development of gas resources at TEN is anticipated following the commencement of oil startup.

Drilling of the Akasa-2A appraisal well on the WCTP Block was completed in October 2013. We believe that the well successfully identified the down dip water contact associated with the Akasa-1 discovery as intended. Should the Akasa discovery progress to a development, the Akasa-2A appraisal well is expected to be utilized in the development as a water injection well. However, since the Akasa-2A appraisal well did not encounter oil or gas reserves sufficient to be utilized as a producing well, accounting rules require that the costs associated with the Akasa-2A appraisal well be impaired. As such, \$20.0 million is included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2013.

*Morocco*

In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013.

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In August 2013, final government approvals and processes were completed for the acquisition of the additional 18.75% participating interest in the Fom Assaka block in the Agadir Basin offshore Morocco from Pathfinder, a wholly owned subsidiary of Fastnet, one of our block partners.

In October 2013, Kosmos executed a petroleum agreement with the Office National des Hydrocarbures et des Mines ("ONHYM"), the national oil company of the Kingdom of Morocco, covering the Tarhazoute Offshore block, to which the Company previously held certain exploration rights under a 2011 reconnaissance contract. Under the terms of the petroleum contract, the Company is the operator of the Tarhazoute Offshore block. ONHYM holds a 25% carried interest in the block through the exploration period. The initial exploration period will last for two years and six months and will commence from the date specified in the exploration permits, which have yet to be finalized with the Government of Morocco and ONHYM. The exploration period may be extended for additional exploration extension periods of two years and six months and three years respectively. The petroleum contract is subject to customary government approvals.

In October 2013, we entered into three farm-out agreements with BP plc ("BP") covering three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Fom Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of \$120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of \$120.0 million per well. Upon close of the transaction, BP shall also pay \$36.3 million for their share of past costs and \$8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Fom Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

In October 2013, we entered into a farm-out agreement with Capricorn Exploration & Development Company Limited, a wholly owned subsidiary of Cairn Energy PLC ("Cairn"), covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at \$25.0 million and one exploration well capped at \$100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at \$100.0 million per well. Additionally, Cairn will contribute \$12.3 million towards our future costs and, upon completion of the transaction, \$0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator.

*Ireland*

In April 2013, the Company entered into a farm-in agreement with Antrim Energy Inc., whereby Kosmos acquired a 75% participating interest and operatorship, covering Licensing Option 11/5 offshore the west coast of Ireland. As part of the agreement, Kosmos will reimburse a portion of previously-incurred exploration costs, as well as carry the partner on future 3D seismic costs.

In April 2013, the Company entered into a farm-in agreement with Europa Oil & Gas (Holdings) plc, whereby Kosmos acquired an 85% participating interest and operatorship, covering Licensing Option 11/7 and 11/8 offshore the west coast of Ireland. As part of the agreement, Kosmos will reimburse a portion of previously incurred exploration costs, as well as carry the partner on future

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3D seismic costs. Contingent upon an election by Kosmos and our partner to enter into a subsequent exploration drilling phase on one or both of the blocks, Kosmos will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap of \$90.0 million and \$110.0 million, respectively, on each block.

In July 2013, Ireland granted us Frontier Exploration Licenses 1-13, 2-13, and 3-13 pursuant to Licensing Options 11/5, 11/7 and 11/8. The term of each contract is 15 years unless surrendered or revoked, and is divided into an initial phase of three years, and three subsequent phases of four years each. Relinquishment of 25% of the existing area is required at the end of the first phase and 50% of the existing area at the end of the second phase. Three months before the end of each phase, we must propose a work program for the subsequent phase for the approval of the Minister of Communications, Energy and Natural Resources. The second phase work program must include an exploration well. The contract area must be surrendered if a second exploration well has not been commenced by the end of the third phase. Upon entering these Frontier Exploration Licenses, we and the other block partners relinquished approximately 25% of the acreage covered by the Licensing Options.

We completed a 3D seismic data acquisition program of approximately 5,000 square kilometers over these blocks in October 2013. The processing of this seismic data is expected to be completed in 2014.

*Mauritania*

In May 2013, we completed a 2D seismic data acquisition program on approximately 6,000 line-kilometers, covering Blocks C8, C12 and C13 offshore Mauritania. In November 2013, we completed a 3D seismic program of approximately 10,300 square kilometers over portions of Blocks C8 and C12. The processing of this seismic data is expected to be completed in 2014.

*Suriname*

In August 2013, we completed a 2D seismic program of approximately 1,400 line kilometers over a portion of Block 42, outside of the existing 3D seismic survey. Processing and interpretation of the data continues.

*Cameroon*

Drilling of the Sipo-1 exploration well on the Ndian River Block was completed in May 2013. Oil and gas shows evidenced during drilling indicated a working petroleum system; however, the well failed to encounter commercial reservoirs and accordingly was plugged and abandoned. Total well and other related costs of \$75.6 million are included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2013.

During 2013, we took all actions required to voluntarily relinquish all of the area under the Ndian River Block and Fako Block in Cameroon.

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**Results of Operations**

All of our results, as presented in the table below, represent operations from the Jubilee Field in Ghana. Certain operating results and statistics for the years ended December 31, 2013, 2012 and 2011 are included in the following table:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands, except per barrel data)		
<b>Sales volumes:</b>			
MBbl	7,778	5,905	5,971
<b>Revenues:</b>			
Oil sales	\$ 851,212	\$ 667,951	\$ 666,912
Average sales price per Bbl	109.44	113.12	111.70
<b>Costs:</b>			
Oil production, excluding workovers	\$ 57,608	\$ 50,640	\$ 83,551
Oil production, workovers	39,183	44,469	
<b>Total oil production costs</b>	<b>\$ 96,791</b>	<b>\$ 95,109</b>	<b>\$ 83,551</b>
<b>Depletion</b>	<b>\$ 213,732</b>	<b>\$ 178,568</b>	<b>\$ 135,532</b>
<b>Average cost per Bbl:</b>			
Oil production, excluding workovers	\$ 7.41	\$ 8.58	\$ 13.99
Oil production, workovers	5.04	7.53	
<b>Total oil production costs</b>	<b>12.45</b>	<b>16.11</b>	<b>13.99</b>
<b>Depletion</b>	<b>27.48</b>	<b>30.24</b>	<b>22.70</b>
<b>Oil production cost and depletion costs</b>	<b>\$ 39.93</b>	<b>\$ 46.35</b>	<b>\$ 36.69</b>

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

#### *Year Ended December 31, 2013 vs. 2012*

	Years Ended December 31,		Increase (Decrease)
	2013	2012	
(In thousands)			
<b>Revenues and other income:</b>			
Oil and gas revenue	\$ 851,212	\$ 667,951	\$ 183,261
Interest income	275	1,108	(833)
Other income	941	3,150	(2,209)
<b>Total revenues and other income</b>	<b>852,428</b>	<b>672,209</b>	<b>180,219</b>
<b>Costs and expenses:</b>			
Oil and gas production	96,791	95,109	1,682
Exploration expenses	230,314	97,712	132,602
General and administrative	158,421	160,027	(1,606)
Depletion and depreciation	222,544	185,707	36,837
Amortization deferred financing costs	11,054	8,984	2,070
Interest expense	36,811	52,207	(15,396)
Derivatives, net	17,027	31,490	(14,463)
Loss on extinguishment of debt		5,342	(5,342)
Other expenses, net	3,512	1,475	2,037
<b>Total costs and expenses</b>	<b>776,474</b>	<b>638,053</b>	<b>138,421</b>
<b>Income (loss) before income taxes</b>	<b>75,954</b>	<b>34,156</b>	<b>41,798</b>
Income tax expense	166,998	101,184	65,814
<b>Net income (loss)</b>	<b>\$ (91,044)</b>	<b>\$ (67,028)</b>	<b>\$ (24,016)</b>

*Oil and gas revenue.* Oil and gas revenue increased by \$183.3 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012, primarily due to an increase in sales volumes. We lifted and sold approximately 7,778 MBbl at an average realized price per barrel of \$109.44 in 2013 and approximately 5,905 MBbl at an average realized price per barrel of \$113.12 in 2012.

*Oil and gas production.* Oil and gas production costs increased by \$1.7 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The change is due to an increase in routine operating expenses offset by a reduction in workover and rig equipment costs. During the year ended December 31, 2013, we incurred workover costs for two water injection wells. During the year ended December 31, 2012, we incurred workover costs related to acid jobs for six producing wells.

*Exploration expenses.* Exploration expenses increased by \$132.6 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. During the year ended December 31, 2013, we incurred \$105.8 million of unsuccessful well and other related costs primarily related to the Cameroon Sipo-1 exploration well; the Ghana Sapele-1 exploration well; and the Ghana Akasa-2A appraisal well and \$110.4 million for seismic costs primarily for Mauritania, Ireland, Morocco and new business activities. During the year ended December 31, 2012, we incurred \$53.9 million for seismic costs for Morocco, Suriname, Ghana and Cameroon; \$32.2 million of unsuccessful well costs, primarily related to the Ghana Teak-4A appraisal well and Ghana Okure-1 exploration well; and \$9.9 million of new business costs.



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*General and administrative.* General and administrative costs decreased by \$1.6 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. Cash General and administrative costs increased \$16.0 million during the year due to an increase in professional fees and compensation and benefits; however, this was partially offset by a \$14.4 million decrease in non-cash general and administrative costs associated with our long-term incentive plan.

*Depletion and depreciation.* Depletion and depreciation increased \$36.8 million during the year ended December 31, 2013, as compared with the year ended December 31, 2012, primarily due to depletion related to an increase in production volumes during the year.

*Interest expense.* Interest expense decreased by \$15.4 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily due to reduced transaction taxes, decreases in our outstanding debt balance and the mark-to-market changes on our interest rate swaps during the year ended December 31, 2013.

*Derivatives, net.* The decrease in Derivatives, net is due to the change in fair value of the commodity derivative instruments. The change in fair value includes the impact of increases and decreases in the Dated Brent forward curve compared to our executed hedging arrangements and derivatives entered into or settled during each period.

*Income tax expense.* The Company recognized an income tax provision attributable to earnings of \$167.0 million and \$101.2 million during 2013 and 2012, respectively. The Company's effective tax rates for 2013 and 2012 were 219.9% and 296.2%, respectively. The large effective tax rates for the periods presented are due to losses incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits as well as losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such losses. Income tax expense increased \$65.8 million during the year ended December 31, 2013, as compared with December 31, 2012, primarily due to an increase in pre-tax income from our Ghanaian subsidiary.

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	Years Ended December 31,		Increase (Decrease)
	2012	2011	
(In thousands)			
<b>Revenues and other income:</b>			
Oil and gas revenue	\$ 667,951	\$ 666,912	\$ 1,039
Interest income	1,108	9,093	(7,985)
Other income	3,150	775	2,375
<b>Total revenues and other income</b>	<b>672,209</b>	<b>676,780</b>	<b>(4,571)</b>
<b>Costs and expenses:</b>			
Oil and gas production	95,109	83,551	11,558
Exploration expenses	100,652	128,753	(28,101)
General and administrative	157,087	111,235	45,852
Depletion and depreciation	185,707	140,469	45,238
Amortization deferred financing costs	8,984	16,193	(7,209)
Interest expense	52,207	65,749	(13,542)
Derivatives, net	31,490	11,777	19,713
Loss on extinguishment of debt	5,342	59,643	(54,301)
Doubtful accounts expense		(39,782)	39,782
Other expenses, net	1,475	149	1,326
<b>Total costs and expenses</b>	<b>638,053</b>	<b>577,737</b>	<b>60,316</b>
Income before income taxes	34,156	99,043	(64,887)
Income tax expense	101,184	76,686	24,498
Net income (loss)	\$ (67,028)	\$ 22,357	\$ (89,385)

*Oil and gas revenue.* Oil and gas revenue increased by \$1.0 million during the year ended December 31, 2012 as compared to the year ended December 31, 2011, primarily due to a higher realized price per barrel. We lifted and sold approximately 5,905 MBbl at an average realized price per barrel of \$113.12 in 2012 and approximately 5,971 MBbl at an average realized price per barrel of \$111.70 in 2011.

*Interest income.* Interest income decreased by \$8.0 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to interest on notes receivable. The related notes receivable was satisfied 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 increased by \$2.4 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to an increase in technical services fees and overhead charges billed to partners.

*Oil and gas production.* Oil and gas production costs increased by \$11.6 million during the year ended December 31, 2012 as compared to the year ended December 31, 2011, primarily due to \$44.5 million of workover costs related to acid stimulations on Jubilee Field wells, offset by a decrease due to the purchase of the FPSO in December 2011. During the year ended December 31, 2012, the amortization of costs capitalized in connection with the purchase of the FPSO were expensed as depletion. Our average production cost per barrel was \$16.11 and \$13.99 for the years ended December 31, 2012 and 2011, respectively.





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*Exploration expenses.* Exploration expenses decreased by \$28.1 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011. During the year ended December 31, 2012, we incurred \$53.9 million for seismic costs for Morocco, Suriname, Ghana and Cameroon; \$32.2 million of unsuccessful well costs, primarily related to the Ghana Teak-4A appraisal well and Ghana Okure-1 exploration well; and \$9.9 million of new business costs. 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.

*General and administrative.* General and administrative costs increased by \$45.9 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to increases in non-cash expenses of \$32.4 million for equity-based compensation and an increase in staffing. Total non-cash general and administrative costs were \$83.4 million and \$51.0 million for the years ended December 31, 2012 and 2011, respectively.

*Depletion and depreciation.* Depletion and depreciation increased \$45.2 million during the year ended December 31, 2012, as compared with the year ended December 31, 2011, primarily due to an increase in the cost basis of our oil and gas properties related to the purchase of the FPSO and an increase in the number of completed wells.

*Amortization deferred financing costs and Loss on extinguishment of debt.* In March 2011, we refinanced our existing commercial debt facilities. As part of the transaction, we incurred approximately \$52.3 million of deferred financing costs, in addition to our existing unamortized deferred financing costs of \$68.6 million. As a result of the transaction, we recorded a \$59.6 million loss on the extinguishment of debt. The remaining costs were capitalized and are being amortized over the term of the Facility. The related amortization of deferred financing costs for the Facility decreased by \$7.5 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, due to the decrease in capitalized deferred financing costs and the longer term associated with the Facility. In November 2012, we amended the Facility and secured a \$300 million Corporate Revolver. As a result of these transactions, \$5.3 million of deferred financing costs were written off as a loss on extinguishment of debt.

*Interest expense.* Interest expense decreased by \$13.5 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to a decrease in the unrealized loss on the interest rate derivative instruments related to changes in fair value and a lower weighted average interest rate on the Facility, partially offset by an accrual for transaction taxes during the year ended December 31, 2012.

*Derivatives, net.* Derivatives, net increased \$19.7 million during the year ended December 31, 2012, as compared with December 31, 2011, due to the change in fair value and notional amount 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.* The Company recognized an income tax provision attributable to earnings of \$101.2 million and \$76.7 million during 2012 and 2011, respectively. The Company's effective tax rates for 2012 and 2011 were 296.2% and 77.4%, respectively. The large variance in income taxes between 2012 and 2011 is due to the impact of the book/tax difference related to the decrease in fair value of certain vested equity awards. The large effective tax rate in 2012 is due to losses incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits; losses in jurisdictions in which we have valuation allowances against our deferred tax assets

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and therefore we do not realize any tax benefit on such losses; and the impact on deferred tax assets based on the book/tax difference related to the decrease in fair value of certain vested equity awards.

**Liquidity and Capital Resources**

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to exploring for and developing oil and natural gas resources along the Atlantic Margin. We have historically met our funding requirements through cash flows generated from our operating activities and secured funding from issuances of equity and commercial debt facilities to meet our ongoing liquidity requirements. In relation to cash flow generated from our operating activities, if we are unable to resolve issues related to the continuous removal of associated natural gas in large quantities from the Jubilee Field, and the production restraints caused thereby, then the Company's cash flows from operations will be adversely affected. 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 Sources of Capital*

*Facility*

The Company maintains a commercial debt facility, as amended, (the "Facility") with a number of financial institutions, including the International Finance Corporation with a total commitment of \$1.5 billion.

As of December 31, 2013, borrowings under the Facility totaled \$900.0 million and the undrawn availability under the Facility was \$309.5 million.

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). We pay commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees 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. We recognize interest expense in accordance with ASC 835 Interest, which requires interest expense to be recognized using the effective interest method. We determine the effective interest rate based on the estimated level of future borrowings under the Facility.

The Facility provides a revolving-credit and letter of credit facility. The availability period for the revolving-credit facility, as amended in April 2013 expires on December 15, 2014 and the letter of credit sublimit expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on December 15, 2014, outstanding borrowings will be constrained by an amortization schedule as well. The first required payment could be as early as March 31, 2015, subject to the level of outstanding borrowings and the borrowing base constraints. The Facility has a final maturity date of March 29, 2018.

We have 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 March 31 and September 30 as part of a forecast that is prepared by and agreed to by us 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.

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If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by us. The Facility contains cross default provisions related to the Corporate Revolver and Revolving Credit Facility.

We were in compliance with the financial covenants contained in the Facility as of the September 30, 2013 forecast (the most recent assessment date), which requires the maintenance of:

the field life cover ratio (as defined in the glossary), not less than 1.30x; and

the loan life cover ratio (as defined in the glossary), not less than 1.10x.

In connection with the Facility, as amended, certain terms of the Facility were amended as follows:

the addition of certain financial covenants such that the Company is required every six months or on a pro forma basis upon giving effect to certain specified transactions to maintain:

the debt cover ratio (as defined in the glossary), not more than 3.5x; and

the interest cover ratio (as defined in the glossary), not less than 2.25x;

to allow proceeds from any project permitted to be funded by the Facility to be used, in accordance with certain payment priority provisions, to pay amounts of interest due under, and fees and expenses related to, the \$300.0 million Corporate Revolver and certain other debt that may be incurred by the Company;

the cancellation of \$500 million of commitments and the right of the Company to increase the Facility commitments beyond \$2.0 billion (i.e. the cancellation of the uncommitted \$1.0 billion accordion);

to permit (i) subsidiaries of the Company (other than certain of the Company's indirect subsidiaries which hold interests in Kosmos Energy Ghana HC) to incur certain indebtedness and guarantees, and grant certain liens over their assets, and (ii) the Ghana Obligors to guarantee the Corporate Revolver and certain other debt that may be incurred by the Company on a subordinated basis, in each case to the extent permitted by the Amended and Restated Facility Agreement and the intercreditor agreement entered into by us and the lenders under the Facility and the Corporate Revolver;

the exclusion of certain of the Company's Morocco and Cameroon subsidiaries from (i) certain restrictions related to granting of security in those subsidiaries' and (ii) the receipt of funds from draws under the Facility; and

to make certain other amendments to the terms of the Facility.

### *Corporate Revolver*

In November 2012, we secured a Corporate Revolver from a number of financial institutions. In April 2013, the availability under the Corporate Revolver was increased from \$260.0 million to \$300.0 million by additional commitments from existing and new financial institutions. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs and corporate activities.

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As of December 31, 2013, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was \$300.0 million.

Interest is the aggregate of the applicable margin (6.0%), LIBOR and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first

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day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 40% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver has a 3-year availability period that expires on November 20, 2015. The available amount is not subject to borrowing base constraints. We have the right to cancel all the undrawn commitments under the Corporate Revolver. We are required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2013 (the most recent assessment date), which requires the maintenance of:

the debt cover ratio (as defined in the glossary), not more than 3.5x; and

the interest cover ratio (as defined in the glossary), not less than 2.25x.

The U.S. and many foreign economies continue to experience uncertainty driven by varying macroeconomic conditions. Although some of these economies have shown signs of improvement, macroeconomic recovery remains uneven. Uncertainty in the macroeconomic environment and associated global economic conditions have resulted in extreme volatility in credit, equity, and foreign currency markets, including the European sovereign debt markets and volatility in various other markets. If any of the financial institutions within our Facility or Corporate Revolver are unable to perform on their commitments, our liquidity could be impacted. We actively monitor all of the financial institutions participating in our Facility and Corporate Revolver. None of the financial institutions have indicated to us that they may be unable to perform on their commitments. In addition, we periodically review our banking and financing relationships, considering the stability of the institutions and other aspects of the relationships. Based on our monitoring activities, we currently believe our banks will be able to perform on their commitments. The Corporate Revolver contains cross default provisions related to the Facility and the Revolving Credit Facility.

*Letter of Credit Facility*

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility is \$100.0 million, with additional commitments up to \$50.0 million being available if the existing lender increases its commitments or if commitments from new financial institutions are added. The LC Facility provides that we shall maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%. The fees associated with outstanding letters of credit issued will be 0.5% per annum. The LC Facility has an availability period which expires on June 1, 2016. We may voluntarily cancel any commitments available under the LC Facility at any time. As of December 31, 2013, there were six outstanding letters of credit totaling \$42.0 million under the LC Facility. The LC Facility contains cross default provisions related to the Facility and the Corporate Revolver.

*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 2014 exploration and appraisal drilling program in our license areas;

develop our discoveries that we determine to be commercially viable;

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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 have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our participating 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, development efforts or any other activity more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

*2014 Capital Program*

We estimate we will incur approximately \$575.0 million of capital expenditures for the year ending December 31, 2014. This capital expenditure budget consists of:

approximately \$400 million for developmental related expenditures offshore Ghana; and

approximately \$175 million for exploration and appraisal related expenditures, including new venture opportunities.

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 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, 2013:

	<b>December 31, 2013</b>
	<b>(In thousands)</b>
Cash and cash equivalents	\$ 598,108
Drawings under the Facility	900,000
<b>Net debt</b>	<b>301,892</b>
Availability under the Facility	\$ 309,504
Availability under the Corporate Revolver	300,000
Available borrowings plus cash and cash equivalents	1,207,612
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	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Net cash provided by (used in):			
Operating activities	\$ 522,404	\$ 371,530	\$ 364,909
Investing activities	(324,133)	(402,662)	(385,140)
Financing activities	(115,327)	(126,796)	592,908

**Operating activities.** Net cash provided by operating activities in 2013 was \$522.4 million compared with net cash provided by operating activities of \$371.5 million in 2012 and \$364.9 million in 2011, respectively. The increase in cash provided by operating activities in 2013 when compared to 2012 was primarily due to an increase in oil and gas revenues and a positive change in working capital items. The increase in cash provided by operating activities in 2012 when compared to 2011 was primarily due to positive change in working capital items which offset a decrease in results from operations.

**Investing activities.** Net cash used in investing activities in 2013 was \$324.1 million compared with \$402.7 million and \$385.1 million in 2012 and 2011, respectively. The decrease in cash used in investing activities in 2013 when compared to 2012 was primarily attributable to a decrease in expenditures for oil and gas assets. The increase in cash used in investing activities in 2012 when compared to 2011 was primarily attributable to changes in restricted cash, notes receivable and expenditures for oil and gas assets primarily in Ghana for development activities. During 2012, we set aside \$23.7 million of restricted cash to support our exploration related activities. During 2011, we released \$112.0 million of restricted cash and set aside \$26.4 million primarily related to requirements under the Facility.

**Financing activities.** Net cash used in financing activities in 2013 was \$115.3 million compared with net cash used in financing activities of \$126.8 million in 2012 and net cash provided by financing activities of \$592.9 million in 2011. The decrease in cash used in financing activities for 2013 when compared to 2012 was primarily due to a decrease in deferred financing costs. The decrease in cash provided by financing activities for 2012 when compared to 2011 was primarily due to net proceeds received from the IPO of \$580.4 million received in 2011 and an increase in net payments under long-term debt.

**Contractual Obligations**

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2013:

	Payments Due By Year(4)						
	Total	2014	2015	2016	2017	2018	Thereafter
	(In thousands)						
Facility(1)	\$ 900,000	\$	\$ 346,693	\$ 149,428	\$ 292,768	\$ 111,111	\$
Interest payments on long-term debt(2)	134,746	47,417	38,001	25,562	22,005	1,761	
Operating leases	20,718	4,365	3,518	3,158	3,223	3,323	3,131
Atwood Achiever drilling rig contract(3)	652,120	91,035	217,175	217,770	126,140		

- (1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2013. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of December 31, 2013, there were no borrowings under the Corporate Revolver.



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- (2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves at the reporting date and commitment fees related to the Facility and Corporate Revolver.
- (3) Commitments calculated using a day rate of \$595,000 and an estimated rig delivery date of August 1, 2014.
- (4) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments, in our petroleum contracts.

In December 2013, we signed a short-term rig share agreement for the drillship "Maersk Discoverer." The Maersk Discoverer is expected to commence drilling operations in the first half of 2014. The rig share agreement covers a period to drill one exploration well in Morocco at a day rate of approximately \$0.6 million. The well is expected to take approximately 90 days.

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.

	Years Ending December 31,					Liability Fair Value at December 31,	
	2014	2015	2016	2017	2018	Thereafter	2013
(In thousands, except percentages)							
<b>Variable rate debt:</b>							
Facility(1)	\$	\$ 346,693	\$ 149,428	\$ 292,768	\$ 111,111	\$	\$ (900,000)
Weighted average interest rate(2)	3.90%	4.35%	5.79%	7.07%	7.71%		
<b>Interest rate swaps:</b>							
Notional debt amount(3)	\$ 47,033	\$ 16,875	\$ 6,250	\$	\$	\$	\$ (1,116)
Fixed rate payable	2.22%	2.22%	2.22%				
Variable rate receivable(4)	0.40%	0.74%	1.41%				
Notional debt amount(3)	\$ 47,033	\$ 16,872	\$ 6,250	\$	\$	\$	\$ (1,175)
Fixed rate payable	2.31%	2.31%	2.31%				
Variable rate receivable(4)	0.40%	0.74%	1.41%				
Notional debt amount(3)	\$ 1,868	\$	\$	\$	\$	\$	\$ (6)
Fixed rate payable	0.98%						
Variable rate receivable(4)	0.35%						
Notional debt amount(3)	\$ 38,434	\$ 23,137	\$	\$	\$	\$	\$ (437)