

# TRANSATLANTIC PETROLEUM LTD.

## FORM 10-K (Annual Report)

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**UNITED STATES**  
**SECURITIES AND EXCHANGE COMMISSION**  
WASHINGTON, D.C. 20549

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**FORM 10-K**

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(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**

**OR**

☐ **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 001-34574**

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**TRANSATLANTIC PETROLEUM LTD.**

(Exact name of registrant as specified in its charter)

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

**16803 Dallas Parkway**  
**Addison, Texas**  
(Address of principal executive offices)

**None**  
(I.R.S. Employer  
Identification No.)

**75001**  
(Zip Code)

**Registrant's telephone number, including area code: (214) 220-4323**

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
<b>Common shares, par value \$0.10</b>	<b>NYSE MKT</b>

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

**None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T 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 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☒

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of common shares, par value \$0.10 per share, held by non-affiliates of the registrant, based on the last sale price of the common shares on June 28, 2013 (the last business day of the registrant's most recently completed second fiscal quarter), was approximately \$147.7 million. For purposes of this computation, all officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such determination should not be deemed an admission that such officers, directors or 10% beneficial owners are, in fact, affiliates of the registrant.

As of March 7, 2014, there were 37,402,698 common shares outstanding.

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**DOCUMENTS INCORPORATED BY REFERENCE**

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2014 Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

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## **Forward-Looking Statements**

Certain statements in this Annual Report on Form 10-K constitute “forward-looking statements” within the meaning of applicable U.S. and Canadian securities legislation. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as “plans,” “expects,” “estimates,” “budgets,” “intends,” “anticipates,” “believes,” “projects,” “indicates,” “targets,” “objective,” “could,” “should,” “may” or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements, including the factors discussed under Item 1A. Risk Factors in this Annual Report on Form 10-K. Such factors include, but are not limited to, the following: fluctuations in and volatility of the market prices for oil and natural gas products; the ability to produce and transport oil and natural gas; the results of exploration and development drilling and related activities; global economic conditions, particularly in the countries in which we carry on business, especially economic slowdowns; actions by governmental authorities including increases in taxes, legislative and regulatory initiatives related to fracture stimulation activities, changes in environmental and other regulations, and renegotiations of contracts; political uncertainty, including actions by insurgent groups or other conflicts; the negotiation and closing of material contracts; future capital requirements and the availability of financing; estimates and economic assumptions used in connection with our acquisitions; risks associated with drilling, operating and decommissioning wells; actions of third-party co-owners of interests in properties in which we also own an interest; our ability to effectively integrate companies and properties that we acquire; and the other factors discussed in other documents that we file with or furnish to the U.S. Securities and Exchange Commission (the “SEC”) and Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and our course of action would depend upon our assessment of the future, considering all information then available. In that regard, any statements as to: future oil or natural gas production levels; capital expenditures; the allocation of capital expenditures to exploration and development activities; sources of funding for our capital expenditure programs; drilling of new wells; demand for oil and natural gas products; expenditures and allowances relating to environmental matters; dates by which certain areas will be developed or will come on-stream; expected finding and development costs; future production rates; ultimate recoverability of reserves, including the ability to convert probable and possible reserves to proved reserves; dates by which transactions are expected to close; future cash flows, uses of cash flows, collectability of receivables and availability of trade credit; expected operating costs; changes in any of the foregoing and other statements using forward-looking terminology are forward-looking statements, and there can be no assurance that the expectations conveyed by such forward-looking statements will, in fact, be realized.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

Readers should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements.

## Glossary of Selected Oil and Natural Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

**2D seismic.** Geophysical data that depict the subsurface strata in two dimensions.

**3D seismic.** Geophysical data that depict the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic.

**Appraisal wells.** Wells drilled to convert an area or sub-region from the resource to the reserves category.

**Bbl.** One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

**Bbl/d.** Barrels of oil per day.

**Bcf.** One billion cubic feet of natural gas.

**Boe.** Barrels of oil equivalent. Boe is not included in the DeGolyer and MacNaughton reserves report and is derived by the Company by converting natural gas to oil in the ratio of six Mcf of natural gas to one Bbl of oil. The conversion factor is the current convention used by many oil and natural gas companies. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

**Boepd.** Barrels of oil equivalent per day.

**Commercial well; commercially productive well.** An oil and natural gas well which produces oil and natural gas in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

**Completion.** The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

**Developed acreage.** The number of acres which are allocated or assignable to producing wells or wells capable of production.

**Development well.** A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

**Directional drilling.** The technique of drilling a well while varying the angle of direction of a well and changing the direction of a well to hit a specific target.

**Dry hole; dry well.** A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

**Exploitation.** The continuing development of a known producing formation in a previously discovered field, including efforts to maximize the ultimate recovery of oil or natural gas from the field by development wells, secondary recovery equipment or other suitable processes and technology.

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**Exploratory well.** A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well.

**Farm-in or farm-out.** An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location, the completion of other work commitments related to that acreage, or some combination thereof.

**Formation.** A succession of sedimentary beds that were deposited under the same general geologic conditions.

**Frac; fracture stimulation.** A stimulation treatment involving the fracturing of a reservoir and then injecting water, sand and chemicals into the fractures under pressure to stimulate hydrocarbon production in low-permeability reservoirs.

**Gross acres or gross wells.** The total acres or wells, as the case may be, in which a working interest is owned.

**Horizontal drilling.** A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.

**Initial production rate.** Generally, the maximum 24-hour production volume from a well.

**Mbbl.** One thousand stock tank barrels.

**Mboe.** One thousand barrels of oil equivalent.

**Mboepd.** One thousand barrels of oil equivalent per day.

**Mcf.** One thousand cubic feet of natural gas.

**Mcf/d.** One thousand cubic feet of natural gas per day.

**Mmbbl.** One million stock tank barrels.

**Mmboe.** One million barrels of oil equivalent.

**Mmcf.** One million cubic feet of natural gas.

**Mmcf/d.** One million cubic feet of natural gas per day.

**Net acres or net wells.** The sum of the fractional working interests owned in gross acres or gross wells.

**Overriding royalty interest.** An interest in an oil or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

**Play.** A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

**Present value of estimated future net revenues or PV-10.** The present value of estimated future net revenues is an estimate of future net revenues from a property at the date indicated, without giving effect to derivative financial instrument activities, after deducting production and ad valorem taxes, future capital costs, abandonment costs and operating expenses, but before deducting future federal income taxes. The future net

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revenues have been discounted at an annual rate of 10% to determine their “present value.” The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil and natural gas prices and operating and capital costs at the date indicated, at its acquisition date, or as otherwise indicated. We believe that the present value of estimated future net revenues before income taxes, while not a financial measure in accordance with U.S. generally accepted accounting principles (“U.S. GAAP”), is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially.

**Productive well.** A productive well is a well that is not a dry well.

**Proved developed reserves.** Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate.

**Proved reserves.** 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, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

**Proved undeveloped reserves.** Reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

**Recompletion.** An operation within an existing well bore to make the well produce oil or natural gas from a different, separately producible zone other than the zone from which the well had been producing.

**Reasonable certainty.** If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (“EUR”) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

**Reservoir.** A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

**Sales volumes.** The amount of production of oil or natural gas sold after deducting royalties and working interests owned by third parties.

**Shale.** Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

**Standardized measure of discounted future net cash flows or the Standardized Measure.** Under the Standardized Measure, future cash flows for the years ended December 31, 2013, 2012 and 2011 are estimated by applying the simple average spot prices for the trailing twelve month period using the first day of each month beginning on January 1 and ending on December 1 of each respective year, adjusted for fixed and determinable escalations, to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end and future plugging and abandonment costs to determine pre-tax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

**Tcf.** One trillion cubic feet of natural gas.

**Undeveloped acreage.** License or lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

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**Wellhead production.** The volume of oil or natural gas produced after deducting royalties and working interests owned by third parties prior to any oil and natural gas lost or used from wellhead to market.

**Working interest.** The operating interest that gives the owner the right to drill, produce and conduct activities on the property and a share of production.

**PART I****Item 1. Business**

In this Annual Report on Form 10-K, references to “we,” “us,” “our,” or the “Company” refer to TransAtlantic Petroleum Ltd. and its subsidiaries on a consolidated basis. Unless stated otherwise, all sums of money stated in this Annual Report on Form 10-K are expressed in U.S. Dollars.

**Our Business**

We are an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established, yet underexplored, petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2013, we held interests in approximately 1.9 million net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria. As of March 1, 2014, approximately 40% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, the chairman of our board of directors and our chief executive officer.

Based on the reserves report prepared by DeGolyer and MacNaughton, independent petroleum engineers, our estimated proved reserves at December 31, 2013 were approximately 12,221 net Mmboe, of which 79.5% was oil. Of these estimated proved reserves, 54.1% were proved developed reserves. As of December 31, 2013, the PV-10 and Standardized Measure of our proved reserves were \$592.5 million and \$495.8 million, respectively. See “Item 2. Properties—Value of Proved Reserves” for a reconciliation of PV-10 to the Standardized Measure.

**Recent Developments**

*Relinquishment of Sud Craiova Exploration License* . In 2012, the Romanian government temporarily suspended unconventional exploration of hydrocarbons, including fracture stimulation, pending a government review of unconventional drilling and completion techniques. As a result, in May 2013, we notified the Romanian government that we were relinquishing our Sud Craiova exploration license, covering approximately 500,000 net onshore acres in Romania.

*Acquisition of Additional Exploration Acreage in Southeastern Turkey* . On May 20, 2013, we completed the acquisition of three exploration licenses from ARAR Petrol ve Gaz Arama Uretim Pazarlama A.S (“ARAR”). The exploration licenses, which cover an aggregate of 150,000 acres, are located adjacent to our Molla exploration licenses in southeastern Turkey. We are the 100% owner and operator of the licenses. In December 2013, we applied to relinquish one of these exploration licenses.

*TBNG Credit Facility* . In June 2013, our wholly owned subsidiary, Thrace Basin Natural Gas (Türkiye) Corporation (“TBNG”), entered into a 78.8 million New Turkish Lira (approximately \$36.9 million at December 31, 2013) unsecured line of credit with a Turkish bank, of which 60 million New Turkish Lira is available in cash for TBNG and 18.8 million New Turkish Lira is available in the form of non-cash bank guarantees and letters of credit for TBNG and several other of our wholly owned subsidiaries operating in Turkey. We have made two borrowings under this credit facility, each of which has a one-year term at a fixed interest rate of 4.6% per annum. At maturity, we expect to renew the borrowings for one additional year at then current market interest rates. As of December 31, 2013, we had borrowed \$20.0 million under this credit facility.

*Amendment of Purchase Agreement* . In July 2013, our wholly owned subsidiary, TransAtlantic Worldwide, Ltd. (“TransAtlantic Worldwide”) entered into a second amendment (the “Amendment”) to our purchase agreement (the “Purchase Agreement”) with Direct Petroleum Exploration, LLC (formerly Direct Petroleum Exploration, Inc.) (“Direct”). Pursuant to the Amendment, we issued 351,074 common shares to Direct as partial

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payment of certain liquidated damages due under the Purchase Agreement. The parties also agreed that Direct is not eligible for any liquidated damages relating to the coring of the Etropole shale formation, which resulted in the 2013 reversal of a \$5.0 million contingent liability recorded in 2011. The Amendment sets forth a new obligation to drill and test the Deventci-R2 well by May 1, 2014. We achieved target depth on the Deventci-R2 well in January 2014, and the well is currently awaiting completion. The Amendment provides that we will issue \$7.5 million of common shares to Direct if the Deventci-R2 well is a commercial success (as defined in the Purchase Agreement) on or prior to May 1, 2016.

Additionally, the Amendment provides that if the Bulgarian government issues a production concession over our Stefenetz concession area, Direct will be entitled to \$10.0 million of common shares, or a pro rata amount if the production concession is less than 200,000 acres.

*Bulgaria Farm-Out* . In August 2013, TransAtlantic Worldwide entered into a farm-out agreement with Koynare Development Ltd. (“KDL”), a private oil and natural gas investment company. Pursuant to the agreement, KDL will fund 75% of our initial \$40 million work program in Bulgaria, and our wholly owned subsidiary, Direct Petroleum Bulgaria EOOD (“Direct Bulgaria”), will assign KDL a 50% interest in our Koynare concession area. Direct Bulgaria will also assign KDL 50% of its interest in our Stefenetz concession area, subject to LNG Energy Ltd.’s (“LNG”) farm-out interest, in the event that the pending concession application is approved by the Bulgarian government.

*Idil Farm-Out* . In February 2014, our wholly owned subsidiary, TransAtlantic Turkey, Ltd. (“TransAtlantic Turkey”), and Selsinsan Petrol Maden T.O. San ve Tic. Ltd. Sti. (“Selsinsan”) entered into a farm-out agreement with Onshore Petroleum Company AS (“Onshore”), a private oil and gas company. Pursuant to the agreement, Onshore will fund 100% of our initial exploration well, up to \$3.5 million, on the Idil license in southeastern Turkey. Expenses over \$3.5 million will be split equally between us and Onshore. In exchange, TransAtlantic Turkey and Selsinsan will assign Onshore a 50% interest in the Idil license.

*Appointment of New Director* . On February 10, 2014, we appointed Gregory K. Renwick to our board of directors. Mr. Renwick worked at Mobil for 25 years and, under his leadership, Mobil successfully acquired upstream assets in Kazakhstan, Turkmenistan and Azerbaijan. He served as president and chief executive officer of East West Petroleum Corp. from 2010 to 2013 and as the director of business development for Dana Gas PJSC in the United Arab Emirates from 2007 to 2010.

*Reverse Stock Split* . On March 4, 2014, the Company’s shareholders approved a 1-for-10 reverse stock split, which became effective March 6, 2014. Pursuant to the reverse stock split, all shareholders of record received one common share for each ten common shares owned (subject to minor adjustments as a result of fractional shares). The reverse stock split reduced the issued and outstanding common shares from 374,026,984 to 37,402,698. U.S. GAAP requires that the reverse stock split be applied retrospectively to all periods presented. As a result, all common share transactions described herein have been adjusted to reflect the 1-for-10 reverse stock split.

## Our Strengths

We believe that the following strengths provide us with meaningful competitive advantages:

*Significant Exploration Acreage in Known Hydrocarbon Basins*. As of March 1, 2014, we held approximately 1.9 million net acres in Turkey and Bulgaria. The majority of this acreage is exploratory, but lies within areas of known hydrocarbon production. We will seek to actively develop our acreage to monetize production, and we will consider joint ventures or farm-out agreements where appropriate.

*Strong and Experienced Management Team*. Our management team, led by our chairman and chief executive officer, Mr. Mitchell, includes executives and managers with significant industry, operational and technical experience. Mr. Mitchell previously built Riata Energy, Inc. (re-named SandRidge Energy, Inc.) into

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one of the largest privately-held energy companies in the United States before selling his controlling stake in 2006. Upon his departure, Riata Energy, Inc. had 1 Tcf in proved reserves, 300 miles of natural gas-gathering pipeline, more than 34,000 horsepower of natural gas compression, and owned or operated 43 drilling rigs. In 2013, we added four senior technical employees who have substantial experience in geology, horizontal drilling, unconventional reservoirs and completions, and secondary recovery. On average, our operations management team possesses more than 25 years of industry experience. The team manages our operations from our corporate offices near Dallas, Texas.

*Growing Production and Cash Flow.* We increased our proved reserves by 5.4% in 2013. In the second half of 2013, based on our 2013 exit rate, we increased our average daily wellhead production rate by 24%. We expect to continue to grow production and cash flow through the development of our Selmo, Molla, and Thrace Basin exploration licenses and production leases, the development of other exploration properties in Turkey and Bulgaria, and the reduction of our general and administrative expenses and operational inefficiencies.

*Operations in Attractive Regions.* We have focused our operations in countries that have established, yet underexplored petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. Our production in Turkey is subject to a 12.5% royalty rate, and the corporate income tax rate is 20%. We sell our oil based on Brent crude pricing, and natural gas prices are generally higher in Turkey than in North America. During 2013, we realized average prices of \$101.05 per Bbl for our oil sales volumes and \$9.43 per Mcf for our natural gas sales volumes in Turkey. We expect that our properties in Bulgaria will also operate under favorable economic terms. We expect that future production in Bulgaria will be subject to royalty rates ranging from 2.5% to 30%, and corporate income tax rates of 10% after a one-year tax holiday.

## Our Strategy

The following are key elements of our strategy:

*Increase Reserves and Production .* We increased our proved reserves by 5.4% in 2013. In the second half of 2013, based on our 2013 exit rate, we increased our average daily wellhead production rate by 24%. We plan to continue to increase our oil and natural gas reserves and production in Turkey through exploration and development on our Selmo, Molla and Thrace Basin exploration licenses and production leases, including the application of 3D seismic, horizontal drilling and fracture stimulation techniques. In 2014, we plan to drill or participate in the drilling of between 19 and 27 new gross wells in southeastern Turkey and between 14 and 22 new gross wells in northwestern Turkey, and recomplete between 15 and 25 existing gross wells in northwestern Turkey.

*Utilize New 3D Seismic Data to Improve Well Targeting .* During 2013, we spent \$12.8 million shooting 3D seismic over areas of Turkey where 3D seismic data did not previously exist. We expect this new data will improve our ability to target well locations, drill wells and ultimately delineate hydrocarbon reservoirs.

*Expand the Use of Horizontal Drilling.* During 2013, we expanded our use of horizontal drilling, employing it on 13 of 35 wells drilled, with successful results in the Selmo, Molla and Thrace Basin areas. During 2014, we anticipate extensive use of horizontal drilling techniques on our wells in southeastern and northwestern Turkey to more effectively extract hydrocarbons and increase our returns on invested capital.

*Further Expand Fracture Stimulation Program .* In 2013, we expanded our use of hydraulic fracturing technology to complete otherwise low productive formations in Turkey. The evolution of fracturing fluids and stimulation designs has yielded positive results in both northwestern and southeastern Turkey. For 2014, we plan to continue optimizing our hydraulic fracturing techniques to improve well performance and economics .

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### Our Properties and Operations

#### *Summary of Geographic Areas of Operations*

The following table shows net reserves information as of December 31, 2013:

	Proved Developed	Proved Undeveloped	Total Proved	Probable Reserves	Possible Reserves
	Reserves (Mboe)	Reserves (Mboe)	Reserves (Mboe)	(Mboe)	(Mboe)
Turkey	6,617	5,604	12,221	11,958	29,911

#### *Turkey*

As of March 1, 2014, we held interests in 23 onshore and offshore exploration licenses and 12 onshore production leases covering a total of 2.1 million gross acres (1.3 million net acres) in Turkey. As of December 31, 2013, we had total net proved reserves of 9,714 Mbbbl of oil and 15,039 Mmcf of natural gas, net probable reserves of 8,120 Mbbbl of oil and 23,030 Mmcf of natural gas and net possible reserves of 16,877 Mbbbl of oil and 78,205 Mmcf of natural gas in Turkey. During 2013, our average wellhead production was approximately 4,375 net Boepd of oil and natural gas in Turkey. The following summarizes our core producing properties in Turkey:

*Southeastern Turkey* . Substantially all of our oil production is concentrated in southeastern Turkey, primarily in the Selmo, Goksu, Bahar and Arpatepe oil fields. These properties are in close proximity to the Zagros fold belt, which encompasses the oil fields of Iran and Iraq. In 2013, we drilled 10 horizontal wells and five vertical wells in southeastern Turkey.

We hold a 100% working interest in the Selmo production lease. The Selmo oil field is the second largest oil field in Turkey in terms of historical cumulative production and is responsible for the largest portion of our current crude oil production. In 2013, we drilled six horizontal developmental wells in the field, five of which were commercially successful. We also remodeled the Selmo field based on 3D seismic and well control. The static model we developed led us to form a new horizontal drilling plan in the field. For 2013, our wellhead production of crude oil from the Selmo field was 670,711 Bbls at an average rate of approximately 1,838 Bbl/d. Türkiye Petrolleri Anonim Ortaklığı (“TPAO”), a Turkish government-owned oil and natural gas company, and Türkiye Petrol Rafinerileri A.Ş. (“TUPRAS”), a privately-owned oil refinery in Turkey, purchase all of our crude oil production from the Selmo field, which is transported by truck to their neighboring facilities. At March 1, 2014, we had 50 producing wells in the Selmo field, and we plan to drill 10 horizontal development wells in Selmo during 2014.

We hold a 100% working interest in each of our three Molla exploration licenses, which contain the Goksu and Bahar oil fields. In the Goksu field, we are primarily targeting the Mardin formation, and in the Bahar field, we are primarily targeting the Bedinan and Hazro formations. In 2013, we completed five horizontal wells and began shooting approximately 800 sq. km. of 3D seismic over the Molla area. During the first half of 2014, we anticipate drilling two vertical wells in the Bahar field, including a vertical sidetrack of the Bahar-2 well, to better understand the geology in preparation for horizontal drilling in the Molla area.

During 2013, we also drilled the Catak-1 well in the Molla area, and we plan to complete the well in early 2014 using hydraulic fracture stimulation to target the Hazro and Bedinan formations.

We hold a 50% working interest in our Arpatepe production lease and exploration license. For 2013, our wellhead production of crude oil from the Arpatepe field was 56,561 Bbls at an average rate of approximately 155 Bbl/d. At March 1, 2014, we had five producing wells on the Arpatepe production lease, and we plan to drill one or two development wells on the Arpatepe field in 2014.

*Northwestern Turkey* . Substantially all of our natural gas production is concentrated in the Thrace Basin, which is one of Turkey’s most productive onshore natural gas regions. It is located in northwestern Turkey near Istanbul. We have accumulated significant onshore acreage in the Thrace Basin.

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Our goal is to monetize proven formations in the Thrace Basin. For 2013, our wellhead production of natural gas in the Thrace Basin was approximately 3,793 Mmcf, or approximately 10.4 Mmcf/d. In 2013, we drilled three horizontal wells in southern Thrace Basin, six shallow vertical wells in northern Thrace Basin, and 11 conventional vertical wells in the Thrace Basin area. We also completed a 234 sq. km. 3D seismic program in the Osmanli area of the southern Thrace Basin. As of March 1, 2014, we had 123 producing wells on our Thrace Basin properties, and we plan to drill or participate in the drilling of between 14 and 22 new gross wells and recompleting between 15 and 25 existing gross wells in 2014. We plan to target the Mezardere siltstone and the Teslimkoy formation with horizontal drilling. We also expect to drill conventional vertical wells in the area.

### ***Bulgaria***

As of March 1, 2014, we held interests in one onshore exploration concession and one onshore production concession covering a total of 567,000 acres in Bulgaria. During 2013, our wellhead production was approximately 15.8 Mmcf of natural gas on a limited test basis in Bulgaria.

On November 14, 2012, Bulgaria's Council of Ministers awarded our subsidiary, Direct Bulgaria, a 35-year production concession covering the approximately 163,000 acre Koynare concession area (the "Koynare Concession Area"). The Koynare Concession Area contains the Deventci-R1 well, where we discovered a reservoir in the Jurassic-aged Ozirovo formation at a depth of approximately 13,800 feet, which the Bulgarian government has certified as a geologic and commercial discovery. During 2013, our wellhead production was approximately 15.8 Mmcf of natural gas on a limited test basis, which was sold to a compressed natural gas facility adjacent to the Deventci-R1 well.

In August 2013, we entered into a farm-out agreement with KDL, pursuant to which KDL would fund 75% of our initial \$40 million work program in Bulgaria in exchange for a 50% interest in our Koynare Concession Area. We will also assign KDL 50% of our interest in our Stefenetz concession area, subject to LNG's farm-out interest, in the event that the pending concession application is approved by the Bulgarian government.

In January 2012, the Bulgarian Parliament enacted legislation that banned fracture stimulation in the Republic of Bulgaria. The legislation had the effect of preventing conventional drilling and completion activities. As a result, we temporarily suspended drilling and completion operations in Bulgaria in January 2012. In June 2012, the Bulgarian Parliament amended the legislation to clarify that conventional operations were not intended to be affected by the law. Accordingly, our conventional natural gas exploration, development and production activity in Bulgaria resumed in 2013. The current legislation significantly constrains our unconventional natural gas exploration, development and production activities in Bulgaria.

During the second half of 2013, we resumed drilling the Deventci-R2 directional well on our Koynare Concession Area. In January 2014, we reached target depth of 14,100 feet, and the well is currently awaiting completion.

In November 2011, we initiated the application process for a production concession covering approximately 395,000 acres over the southern portion of our former A-Lovech exploration permit (the "Stefenetz Concession Area"). The Stefenetz Concession Area is estimated to contain over 300,000 prospective acres of Etropole shale at a depth of approximately 12,500 feet, which the Bulgarian government has certified as a geologic discovery. During 2012, we initiated an environmental impact assessment which the Bulgarian government must approve prior to granting the production concession. Pursuant to our agreement with LNG, if we obtain a production concession over the Stefenetz Concession Area, LNG would fund an additional \$12.5 million in exchange for a 50% working interest in the production concession. The remaining 50% working interest in the production concession would be split equally between us and KDL.

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### Current Operations

As of March 1, 2014, our wellhead production was an aggregate of approximately 2,800 Bbl/d, primarily from the Selmo production lease, Arpatepe production lease and Molla exploration licenses, and approximately 11.1 Mmcf/d of natural gas, primarily from our various Thrace Basin production leases and exploration licenses. As of March 1, 2014, we were engaged in the following drilling and exploration activities:

*Turkey* . During the first quarter of 2014, we were drilling the Selmo-92H well, our fifth Selmo MSD horizontal well, and completing the Selmo-86H well, and we initiated our first waterflood pilot test in the Selmo field to assess the field's potential for secondary recovery. We also completed the final four stages of the Selmo-36H1 well in the Selmo field and completed the Ambaracik-2 well in the Arpatepe field. We continue to interpret data from our 800 sq. km. 3D seismic program over the Molla exploration licenses. Due to weather conditions, we believe the remaining 3D seismic to be shot over the Goksu field will resume in late April 2014.

*Bulgaria*. We reached target depth of 14,100 feet on the Deventci-R2 well on the Koynare Concession Area in the first quarter of 2014, and the well is currently awaiting completion.

### Planned Operations

We continue to actively explore and develop our existing oil and natural gas properties in Turkey and evaluate opportunities for further activity in Bulgaria. Our success will depend in part on discovering additional hydrocarbons in commercial quantities and then bringing those discoveries to production.

We expect our net field capital expenditures for 2014, which includes seismic, to range between \$75.0 and \$100.0 million. We expect net field capital expenditures during 2014 to consist of approximately \$76.0 million of drilling and completion expense for between 33 and 49 gross wells, \$4.0 million of seismic expense and \$8.5 million of infrastructure improvements and other capital investments. Of these expenditures, we expect to spend approximately 15% in northwestern Turkey, devoted to developing conventional and unconventional natural gas production and building infrastructure. Most of the remaining 85% of these anticipated expenditures is expected to be invested in southeastern Turkey, devoted to drilling developmental and exploratory oil wells at Selmo, Arpatepe and Molla and acquiring seismic data. We expect cash on hand, borrowings from our credit facilities, including our planned debt refinancing, and cash flow from operations will be sufficient to fund our 2014 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2014 capital expenditure budget is subject to change.

*Exploration, Development and Production*. We currently plan to execute the following drilling and exploration activities during 2014:

*Turkey*. We plan to drill between 33 and 49 gross wells, of which 26 are expected to be drilled horizontally and approximately 60% of which will be fracture stimulated. We also plan to execute at least four waterflood pilot tests and construct the infrastructure necessary to produce and sell oil and natural gas from the productive wells we drill.

*Bulgaria* . We spud the Deventci-R2 well on our Koynare Concession Area in October 2013 and reached target depth in January 2014. We may drill an additional well in Bulgaria, depending on the results of the Deventci-R2 well.

### Principal Markets

In accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 280, *Segment Reporting* ("ASC 280"), we currently have two reportable geographic segments: Bulgaria and Turkey. For financial information about our operating segments and geographic areas, refer to "Note 12—Segment information" to our consolidated financial statements.

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### Customers

*Oil* . During 2013, 71.3% of our oil production was concentrated in the Selmo field in Turkey. TUPRAS purchases the majority of our oil production from the Selmo field. During 2013, we sold \$87.2 million of oil to TUPRAS, representing approximately 66.7% of our total revenues. We sell our oil to TUPRAS pursuant to a domestic crude oil purchase and sale agreement. Under the purchase and sale agreement, TUPRAS purchases oil produced by us and delivered to our Boru Hatlari ile Petrol Tasima A.S. (“BOTAŞ”) Batman tanks and to the BOTAŞ Dörtüol plant. The price of the oil delivered pursuant to the purchase and sale agreement is determined under the Petroleum Market Law No. 5015 under the laws of the Republic of Turkey. The purchase and sale agreement automatically renews for successive one-year terms unless earlier terminated in writing by either party. No other purchasers of our oil accounted for more than 10% of our total revenues.

*Natural Gas* . During 2013, no purchasers of our natural gas accounted for 10% or more of our total revenues.

### Competition

We operate in the highly competitive areas of oil and natural gas exploration, development, production and acquisition with a substantial number of other companies, including U.S.-based and international companies doing business in each of the countries in which we operate. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- seeking oil and natural gas exploration licenses and production licenses and leases;
- acquiring desirable producing properties or new leases for future exploration;
- marketing oil and natural gas production;
- integrating new technologies; and
- contracting for drilling services and equipment and securing the expertise necessary to develop and operate properties.

Many of our competitors have substantially greater financial, managerial, technological and other resources than we do. To the extent competitors are able to pay more for properties than we are paying, we will be at a competitive disadvantage. Further, many of our competitors enjoy technological advantages over us and may be able to implement new technologies more rapidly than we can. Our ability to explore for and produce oil and natural gas prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

### Fracture Stimulation Program

Oil and natural gas may be recovered from our properties through the use of fracture stimulation combined with modern drilling and completion techniques. Fracture stimulation involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We have successfully utilized fracture stimulation in our Thrace Basin, Molla and Selmo licenses and production leases.

For unconventional reservoirs, including the Mezardere formation in the Thrace Basin, a typical fracture stimulation consists of injecting between 20,000 and 100,000 gallons of fluid that contain between 10,000 and 150,000 pounds of sand. Fluids vary depending on formation and treatment objective but, in general, are either slickwater (fresh water with salt and friction reducer) or a gelled fluid containing organic polymers with a 4% potassium chloride solution and required breakers. Fracture stimulations in Selmo and Molla are conducted in a low permeability carbonate reservoir. These stimulations generally consist of injecting between 20,000 and

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100,000 gallons of fluid that contain between 10,000 and 100,000 pounds of sand. Fluids are generally a mixture of slickwater and 15% hydrochloric acid, which is typical in carbonate stimulation. The size of fracture stimulation treatments is dependent on net pay thickness and the proximity of the hydrocarbon zones of interest to water bearing zones.

Although the cost of each well will vary, on average approximately 30% of the total cost of drilling and completing a well in the unconventional Mezardere formation in the Thrace Basin and approximately 15% of the total cost of re-entering and completing a well at Selmo is associated with fracture stimulation activities. We account for these costs as typical drilling and completion costs and include them in our capital expenditure budget.

We believe that the stacked nature of the sandstone intervals within the Mezardere unconventional formation, which is up to approximately 5,300 feet thick, and the limited number of deep penetrations to date on these structures provides significant opportunities for additional drilling and multi-stage fracs as the program matures.

We diligently review best practices and industry standards in connection with fracture stimulation activities and strive to comply with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across potable water sources, cementing surface casing from setting depth to surface and second string from setting depth up into the surface casing and, in some cases, to surface, continuously monitoring the fracture stimulation process in real time and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources or at a certified water treatment plant. There have not been any incidents, citations or suits involving environmental concerns related to our fracture stimulation operations on our properties.

In the Thrace Basin, Selmo and Molla, we have access to water resources which we believe will be adequate to execute our fracture stimulation program in 2014. We also employ procedures for environmentally friendly disposal of fluids recovered from fracture stimulation, including recycling approximately 50% of these fluids.

For more information on the risks of fracture stimulation, please read “Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry—Our oil and natural gas operations are subject to extensive and complex laws and government regulation in the jurisdictions in which we operate and compliance with existing and future laws may increase our costs or impair our operations” and “Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry—Legislative and regulatory initiatives and increased public scrutiny relating to fracture stimulation activities could result in increased costs and additional operating restrictions or delays.”

## Governmental Regulations

*Government Regulation*. Our current or future operations, including exploration and development activities on our properties, require permits from various governmental authorities, and such operations are and will be governed by laws and regulations concerning exploration, development, production, exports, taxes, labor laws and standards, occupational health, waste disposal, toxic substances, land use, environmental protection and other matters. Compliance with these requirements may prove to be difficult and expensive. Due to our international operations, we are subject to the following issues and uncertainties that can affect our operations adversely:

- the risk of expropriation, nationalization, war, revolution, political instability, border disputes, renegotiation or modification of existing contracts, and import, export and transportation regulations and tariffs;
- laws of foreign governments affecting our ability to fracture stimulate oil or natural gas wells, such as the legislation enacted in Bulgaria in January 2012 and the temporary suspension of unconventional exploration and drilling activities imposed in Romania in 2012;

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- the risk of not being able to procure residency and work permits for our expatriate personnel;
- taxation policies, including royalty and tax increases and retroactive tax claims;
- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over international operations;
- laws and policies of the United States affecting foreign trade, taxation and investment, including anti-bribery and anti-corruption laws;
- the possibility of being subjected to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- the possibility of restrictions on repatriation of earnings or capital from foreign countries.

*Permits and Licenses* . In order to carry out exploration and development of oil and natural gas interests or to place these into commercial production, we may require certain licenses and permits from various governmental authorities. There can be no guarantee that we will be able to obtain all necessary licenses and permits that may be required. In addition, such licenses and permits are subject to change and there can be no assurances that any application to renew any existing licenses or permits will be approved.

*Repatriation of Earnings* . Currently, there are no restrictions on the repatriation of earnings or capital to foreign entities from Turkey or Bulgaria. However, there can be no assurance that any such restrictions on repatriation of earnings or capital from the aforementioned countries or any other country where we may invest will not be imposed in the future. We may be liable for the payment of taxes upon repatriation of certain earnings from the aforementioned countries.

*Environmental* . The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which we operate. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products and waste created by water and air pollution control procedures. These regulations can have an impact on the selection of drilling locations and facilities, and potentially result in increased capital expenditures. In addition, environmental legislation may require those wells and production facilities to be abandoned and sites reclaimed to the satisfaction of local authorities. Such regulation has increased the cost of planning, designing, drilling, operating and, in some instances, abandoning wells. We are committed to complying with environmental and operational legislation wherever we operate.

There has been a recent surge in interest among the media, government regulators and private citizens concerning the possible negative environmental and geological effects of fracture stimulation. Some have alleged that fracture stimulation results in the contamination of aquifers and may even contribute to seismic activity. In January 2012, the government of Bulgaria enacted legislation that banned the fracture stimulation of oil and natural gas wells in the Republic of Bulgaria and imposed large monetary penalties on companies that violate that ban. In 2012, the Romanian government temporarily suspended unconventional drilling and exploration of hydrocarbons, including fracture stimulation, pending a government review of unconventional drilling and completion techniques. As a result of the suspension, we relinquished our Sud Craiova license in Romania. There is a risk that Turkey could at some point impose similar legislation or regulations. Such legislation or regulations could severely impact our ability to drill and complete wells, and could increase the cost of planning, designing, drilling, completing and operating wells. We are committed to complying with legislation and regulations involving fracture stimulation wherever we operate.

Such laws and regulations not only expose us to liability for our own negligence, but may also expose us to liability for the conduct of others or for our actions that were in compliance with all applicable laws at the time

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those actions were taken. We may incur significant costs as a result of environmental accidents, such as oil spills, natural gas leaks, ruptures, or discharges of hazardous materials into the environment, including clean-up costs and fines or penalties. Additionally, we may incur significant costs in order to comply with environmental laws and regulations and may be forced to pay fines or penalties if we do not comply.

### Insurance

We currently carry general liability insurance and excess liability insurance with a combined annual limit of \$21.0 million per occurrence and \$32.0 million in the aggregate. These insurance policies contain maximum policy limits and are subject to customary exclusions and limitations. Our pollution insurance, which is part of our general liability policy, has a per occurrence limit of \$1.0 million and aggregate annual limit of \$2.0 million. Our general liability insurance covers us and our subsidiaries for third-party claims and liabilities arising out of lease operations and related activities. The excess liability insurance is in addition to, and is triggered if, the general liability insurance per occurrence limit is reached.

We also maintain control of well insurance. Our control of well insurance has a per occurrence and combined single limit of \$15.0 million and is subject to deductibles ranging from \$150,000 to \$500,000 per occurrence.

We require our third-party service providers to sign master service agreements with us pursuant to which they agree to indemnify us for the personal injury and death of the service provider's employees as well as subcontractors that are hired by the service provider. Similarly, we generally agree to indemnify our third-party service providers against similar claims regarding our employees and our other contractors.

We also require our third-party service providers that perform fracture stimulation operations for us to sign master service agreements containing the indemnification provisions noted above. We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to fracture stimulation operations. We believe that our general liability, excess liability and pollution insurance policies would cover third-party claims related to fracture stimulation operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated environmental clean-up responsibilities.

### Bermuda Tax Exemption

As a Bermuda exempted company and under current Bermuda law, we are not subject to tax on profits, income or dividends, nor is there any capital gains tax applicable to us in Bermuda. Profits can be accumulated, and it is not obligatory for us to pay dividends.

Furthermore, we have received an assurance from the Minister of Finance of Bermuda under the Exempted Undertakings Tax Protection Act 1966, as amended, that in the event that Bermuda enacts any legislation imposing tax computed on profits, income, any capital asset, gain or appreciation, we and any of our operations or our shares, debentures or other obligations shall be exempt from the imposition of such tax until March 31, 2035, provided that such exemption shall not prevent the application of any tax payable in accordance with the provisions of the Land Tax Act, 1967 or otherwise payable in relation to land in Bermuda leased to us.

We are required to pay an annual government fee (the "AGF"), which is determined on a sliding scale by reference to our authorized share capital and share premium account, with a minimum fee of \$1,995 Bermuda Dollars and a maximum fee of \$31,120 Bermuda Dollars. The Bermuda Dollar is treated at par with the U.S. Dollar. The AGF is payable each year on or before the end of January and is based on the authorized share capital and share premium account on August 31 of the preceding year.

In Bermuda, stamp duty is not chargeable in respect of the incorporation, registration, licensing of an exempted company or, subject to certain minor exceptions, on their transactions.

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### Employees

As of March 1, 2014, we employed 287 people. Approximately 41 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with the Petroleum, Chemical and Rubber Workers Union of Turkey (“PETROL-IS”). We are currently negotiating a collective bargaining agreement with PETROL-IS covering approximately 36 employees at another of our subsidiaries operating in Turkey. We consider our employee relations to be satisfactory.

### Formation

We were incorporated under the laws of British Columbia, Canada on October 1, 1985 under the name Profco Resources Ltd. and continued to the jurisdiction of Alberta, Canada under the *Business Corporations Act* (Alberta) on June 10, 1997. Effective December 2, 1998, we changed our name to TransAtlantic Petroleum Corp. Effective October 1, 2009, we continued to the jurisdiction of Bermuda under the *Bermuda Companies Act 1981* under the name TransAtlantic Petroleum Ltd.

### Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), are made available free of charge on our website at [www.transatlanticpetroleum.com](http://www.transatlanticpetroleum.com) as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC.

### Executive Officers of the Registrant

The following table and text sets forth certain information with respect to the Company’s executive officers as of March 1, 2014:

Name	Age	Positions
N. Malone Mitchell 3 <sup>rd</sup>	52	Chairman and Chief Executive Officer
Ian J. Delahunty	34	President
Wil F. Saqueton	44	Vice President and Chief Financial Officer
Jeffrey S. Mecom	48	Vice President, Legal and Corporate Secretary

*N. Malone Mitchell 3<sup>rd</sup>* has served as our chief executive officer since May 2011, as a director since April 2008 and as our chairman since May 2008. Since 2005, Mr. Mitchell has served as the president of Riata Corporate Group, LLC, a Dallas-based private oil and natural gas exploration and production company. From June to December 2006, Mr. Mitchell served as president and chief operating officer of SandRidge Energy, Inc. (formerly Riata Energy, Inc.), an independent oil and natural gas company concentrating in exploration, development and production activities. Until he sold his controlling interest in Riata Energy, Inc. in June 2006, Mr. Mitchell also served as president, chief executive officer and chairman of Riata Energy, Inc., which Mr. Mitchell founded in 1985 and built into one of the largest privately held energy companies in the United States.

*Ian J. Delahunty* has served as our president since January 2013. Mr. Delahunty served as our vice president, business development from February 2012 until his promotion to president. He joined us in October 2008 and has worked with our operations in Turkey, Romania and Morocco, serving as our vice president, engineering overseeing completions and workovers from November 2009 to January 2012. Prior to joining us, he worked as a senior engineer with Schlumberger N.V. in Vietnam and the United States and as a completions engineer with Occidental Petroleum Corp. in the United States.

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*Wil F. Saqueton* has served as the Company's vice president and chief financial officer since August 2011. Mr. Saqueton previously served as the Company's corporate controller from May 2011 until August 2011 and as a consultant to the Company from February 2011 until May 2011. Prior to joining the Company, Mr. Saqueton served as the vice president and chief financial officer of BCSW, LLC, the owner of Just Brakes in Dallas, Texas, from July 2006 to December 2010. From July 1995 until July 2006, he held a variety of positions at Intel Corporation, including strategic controller at the Chipset Group, operations controller at the Americas Sales and Marketing Organization Division, finance manager at the Intel Online Services, Inc. Division and senior financial analyst at the Chipset Group. Prior to 1995, Mr. Saqueton was a senior associate at Price Waterhouse, LP.

*Jeffrey S. Mecom* has served as the Company's corporate secretary since May 2006 and as a vice president since May 2007. Before joining the Company in April 2006, Mr. Mecom was an attorney in private practice in Dallas. Mr. Mecom served as vice president, legal and corporate secretary with Aleris International, Inc., a former NYSE-listed international metals recycling and processing company, from 1995 until April 2005.

### Item 1A. Risk Factors

#### Risks Related to Our Business

***We have a history of losses and may not achieve consistent profitability in the future.***

We have incurred substantial losses in prior years. During 2013, we generated a net loss from continuing operations of \$13.3 million. We will need to generate and sustain increased revenue levels in future periods in order to become consistently profitable, and even if we do, we may not be able to maintain or increase our level of profitability. We may incur losses in the future for a number of reasons, including risks described herein, unforeseen expenses, difficulties, complications and delays, and other unknown risks.

***Our exploration, development and production activities may not be profitable or achieve our expected returns.***

The future performance of our business will depend upon our ability to identify, acquire and develop additional oil and natural gas reserves that are economically recoverable. Success will depend upon our ability to acquire working and revenue interests in properties upon which oil and natural gas reserves are ultimately discovered in commercial quantities, and the ability to develop prospects that contain additional proven oil and natural gas reserves to the point of production. Without successful acquisition and exploration activities, we will not be able to develop additional oil and natural gas reserves or generate additional revenues. There are no assurances that additional oil and natural gas reserves will be identified or acquired on acceptable terms, or that oil and natural gas reserves will be discovered in sufficient quantities to enable us to recover our exploration and development costs or sustain our business.

The successful acquisition and development of oil and natural gas properties requires an assessment of recoverable reserves, future oil and natural gas prices and operating costs, potential environmental and other liabilities, and other factors. Such assessments are inherently uncertain. In addition, no assurance can be given that our exploration and development activities will result in the discovery of additional reserves. Operations may be curtailed, delayed or canceled as a result of lack of adequate capital and other factors, such as lack of availability of rigs and other equipment, title problems, weather, compliance with governmental regulations or price controls, mechanical difficulties, or unusual or unexpected formations, pressures and/or work interruptions. In addition, the costs of exploration and development may materially exceed our internal estimates.

***Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.***

Our future success depends on the success of our exploration, development and production activities in each of our prospects. These activities are subject to numerous risks beyond our control, including the risk that we will be unable to economically produce our reserves or be able to find commercially productive oil or natural gas

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reservoirs. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project unprofitable. Further, many factors may curtail, delay or prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- title problems;
- adverse weather conditions;
- lack of market demand for oil and natural gas;
- delays imposed by, or resulting from, compliance with environmental laws and other regulatory requirements;
- declines in oil and natural gas prices; and
- shortages or delays in the availability of drilling rigs, equipment and qualified personnel.

Our future drilling activities might not be successful, and drilling success rates overall or within a particular area could decline. We could incur losses by drilling unproductive wells. Shut-in wells, curtailed production and other production interruptions may materially adversely affect our business, financial condition and results of operations.

***Shortages of drilling rigs, equipment, oilfield services and qualified personnel could delay our exploration and development activities and increase the prices we pay to obtain such drilling rigs, equipment, oilfield services and personnel.***

Our industry is cyclical and, from time to time, there may be a shortage of drilling rigs, equipment, oilfield services and qualified personnel in the countries in which we operate. Shortages of drilling and workover rigs, pipe and other equipment may occur as demand for drilling rigs and equipment increases, along with increases in the number of wells being drilled. These factors can also cause significant increases in costs for equipment, oilfield services and qualified personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly increase our net loss, decrease our cash provided by operating activities, or restrict our ability to conduct the exploration and development activities we currently have planned and budgeted or which we may plan in the future. In addition, the availability of drilling rigs can vary significantly from region to region at any particular time. An undersupply of rigs in any of the regions where we operate may result in drilling delays and higher drilling costs for the rigs that are available in that region.

***We depend on the services of our chairman and chief executive officer.***

We depend on the performance of Mr. Mitchell, our chairman and chief executive officer. The loss of Mr. Mitchell could negatively impact our ability to execute our strategy. We do not maintain a key person life insurance policy on Mr. Mitchell.

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### ***We have concentrated current production of oil in the Selmo oil field, the majority of which is sold to one customer.***

During 2013, we derived 71.3% of our oil production from the Selmo oil field in southeastern Turkey. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, litigation or interruption of the processing or transportation of oil, natural gas or natural gas liquids. In addition, we are currently in litigation with a group of villagers who live around the Selmo oil field and who claim ownership of a portion of the surface rights at Selmo.

In addition, TPAO, the national oil company of Turkey, and TUPRAS, a privately owned oil refinery in Turkey, purchase all of our oil production from the Selmo field. TUPRAS purchases the majority of our oil production from Selmo, representing 66.7% of our total revenues in 2013. If either of these companies fails to purchase our oil production, our results of operations could be materially and adversely affected.

### ***We could lose permits or licenses on certain of our properties unless the permits or licenses are extended or we commence production and convert the permits or licenses to production leases or concessions.***

At December 31, 2013, of our total net undeveloped acreage, 22% and 26% will expire during 2014 and 2015, respectively, unless we are able to extend the permits or licenses covering this acreage or commence production on this acreage and convert the permits or licenses into production leases or concessions. If our permits or licenses expire, we will lose our right to explore and develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control. Such factors include drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

### ***Virtually all of our operations are conducted in Turkey and Bulgaria, and we are subject to political, economic and other risks and uncertainties in these countries.***

Virtually all of our international operations are performed in the emerging markets of Turkey and Bulgaria, which may expose us to greater risks than those associated with more developed markets. Due to our foreign operations, we are subject to the following issues and uncertainties that can adversely affect our operations:

- the risk of, and disruptions due to, expropriation, nationalization, war, revolution, election outcomes, economic instability, political instability, or border disputes;
- the uncertainty of local contractual terms, renegotiation or modification of existing contracts and enforcement of contractual terms in disputes before local courts;
- the risk of import, export and transportation regulations and tariffs, including boycotts and embargoes;
- the risk of not being able to procure residency and work permits for our expatriate personnel;
- the requirements or regulations imposed by local governments upon local suppliers or subcontractors, or being imposed in an unexpected and rapid manner;
- taxation and revenue policies, including royalty and tax increases, retroactive tax claims and the imposition of unexpected taxes or other payments on revenues;
- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over foreign operations;
- laws and policies of the United States and of the other countries in which we operate affecting foreign trade, taxation and investment, including anti-bribery and anti-corruption laws;

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- the possibility of being subjected to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- the possibility of restrictions on repatriation of earnings or capital from foreign countries.

To manage these risks, we sometimes form joint ventures and/or strategic partnerships with local private and/or governmental entities. Local partners provide us with local market knowledge. However, there can be no assurance that changes in conditions or regulations in the future will not affect our profitability or ability to operate in such markets.

### ***Acts of violence, terrorist attacks or civil unrest in southeastern Turkey and nearby countries could adversely affect our business.***

During 2013, we derived 71.3% of our oil production from the Selmo oil field in southeastern Turkey. Historically, the southeastern area of Turkey and nearby countries such as Iran, Iraq and Syria have experienced political, social or economic problems, terrorist attacks, insurgencies or civil unrest. If any of these events, conditions or conflicts occurs, we may be unable to access the locations where we conduct operations. In those locations where we have employees or operations, we may incur substantial costs to maintain the safety of our personnel and our operations. Despite these precautions, the safety of our personnel and operations in these locations may continue to be at risk, and we may in the future suffer the loss of employees and contractors or our operations could be disrupted, any of which could have a material adverse effect on our business and results of operations.

### ***Our amended and restated credit facility contains various covenants that limit our management's discretion in the operation of our business and can lead to an event of default that may adversely affect our business, financial condition and results of operations.***

The operating and financial restrictions and covenants in our amended and restated credit facility (the "Amended and Restated Credit Facility") with BNP Paribas (Suisse) SA ("BNP Paribas") and Standard Bank Plc ("Standard Bank") may adversely affect our ability to finance future operations or capital needs or to engage in other business activities. Our Amended and Restated Credit Facility contains various covenants that restrict our ability to, among other things:

- incur additional debt;
- create liens;
- enter into any hedge agreement for speculative purposes;
- engage in business other than as an oil and natural gas exploration and production company;
- enter into sale and leaseback transactions;
- enter into any merger, consolidation or amalgamation;
- declare or provide for any dividends or other payments or distributions;
- redeem or purchase any shares; or
- guarantee the obligations of any other person.

In addition, the Amended and Restated Credit Facility requires us to maintain specified financial ratios and tests. Various risks, uncertainties and events beyond our control could affect our ability to comply with the covenants and financial tests and ratios required by the Amended and Restated Credit Facility and could result in an event of default under the Amended and Restated Credit Facility.

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An event of default under the Amended and Restated Credit Facility includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control is an event of default. A change of control is defined as the occurrence of any of the following: (i) our failure to own, of record and beneficially, all of the equity of TransAtlantic Exploration Mediterranean International Pty Ltd (“TEMI”), Talon Exploration, Ltd. (“Talon Exploration”), TransAtlantic Turkey, Amity Oil International Pty. Ltd. (“Amity”), Petrogas Petrol Gaz ve Petrokimya Ürünleri İnşaat Sanayi ve Ticaret A.Ş. (“Petrogas”), and DMLP, Ltd. (“DMLP,”) and together with TEMI, Talon Exploration, TransAtlantic Turkey, Amity and Petrogas, the “Borrowers”) or either of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide or to exercise, directly or indirectly, day-to-day management and operational control of any Borrower or TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide; (ii) the failure by the Borrowers to own or hold, directly or indirectly, all of the interests granted to Borrowers pursuant to certain hydrocarbon licenses designated in the Amended and Restated Credit Facility; or (iii) (a) Mr. Mitchell ceases for any reason to be the executive chairman of our board of directors at any time, (b) Mr. Mitchell and certain of his affiliates cease to own of record and beneficially at least 35% of our common shares; or (c) any person or group, excluding Mr. Mitchell and certain of his affiliates, shall become, or obtain rights to become, the beneficial owner, directly or indirectly, of more than 35% of our outstanding common shares entitled to vote for members of our board of directors on a fully-diluted basis. Provided that, if Mr. Mitchell ceases to be executive chairman of our board of directors by reason of his death or disability, such event shall not constitute an event of default unless we have not appointed a successor reasonably acceptable to the lenders within 60 days of the occurrence of such event.

In the event of a default and acceleration of indebtedness under the Amended and Restated Credit Facility, our business, financial condition and results of operations may be materially and adversely affected.

***We have identified material weaknesses in our internal control over financial reporting. These material weaknesses, if not corrected, could affect the reliability of our financial statements and have other adverse consequences.***

Under Section 404 of the Sarbanes-Oxley Act of 2002, we are required to furnish a report by our management on internal control over financial reporting. This report must contain, among other matters, an assessment of the effectiveness of our internal control over financial reporting, including a statement as to whether or not our internal control over financial reporting is effective. This assessment must include disclosure of any material weaknesses in our internal control over financial reporting identified by our management. In addition, the report must contain a statement that our auditors have issued an attestation report on management’s assessment of such internal control over financial reporting.

We have identified material weaknesses in our internal control over financial reporting as of December 31, 2013, as disclosed in “Item 9A. Controls and Procedures”. Failure to have effective internal controls could lead to a misstatement of our financial statements or prevent us from filing our financial statements in a timely manner. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial statements, our business decision processes may be adversely affected, our business and operating results could be harmed, investors could lose confidence in our reported financial information, the price of our common shares could decrease and our ability to obtain additional financing, or additional financing on favorable terms, could be adversely affected. In addition, failure to maintain effective internal control over financial reporting could result in investigations or sanctions by regulatory authorities.

We intend to take further action to remediate the material weaknesses and improve the effectiveness of our internal control over financial reporting. However, we can give no assurances that the measures we may take will remediate the material weaknesses identified or that any additional material weaknesses will not arise in the future due to our failure to implement and maintain adequate internal control over financial reporting. In addition, even if we are successful in strengthening our controls and procedures, those controls and procedures may not be adequate to prevent or identify irregularities or ensure the fair presentation of our financial statements included in our periodic reports filed with the SEC.

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### ***We could experience labor disputes that could disrupt our business in the future.***

As of March 1, 2014, approximately 41 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with PETROL-IS. We are currently negotiating a collective bargaining agreement with PETROL-IS covering approximately 36 employees at another of our subsidiaries operating in Turkey. Potential work disruptions from labor disputes with these employees could disrupt our business and adversely affect our financial condition and results of operations.

### ***We could be assessed for Canadian federal tax as a result of our 2009 continuance under the Bermuda Companies Act 1981.***

For Canadian tax purposes, we were deemed, immediately before the completion of our 2009 continuance under the Bermuda *Companies Act 1981*, to have disposed of each property owned by us for proceeds equal to the fair market value of that property, and will be subject to tax on any resulting net income. In addition, we were required to pay a special “branch tax” equal to 25% of any excess of the fair market value of our property over the “paid-up capital” (as defined in the Income Tax Act (Canada)) of our outstanding common shares and our liabilities. However, management, together with its professional advisors, has determined that the paid-up capital of our common shares and our liabilities exceeded the fair market value of our property, resulting in no “branch tax” being payable. The Canada Revenue Agency (“CRA”) may not accept our determination of the fair market value of our property. In the event that CRA’s determination of fair market value is significantly higher than our valuation and such determination is final, we may be subject to material amounts of tax resulting from the deemed disposition.

## **Risks Related to the Oil and Natural Gas Industry**

### ***Reserves estimates depend on many assumptions that may turn out to be inaccurate.***

Any material inaccuracies in our reserves estimates or underlying assumptions could materially affect the quantities and present values of our reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves that we may report. In order to prepare these estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to 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 most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves that we may report. In addition, we may adjust estimates of proved, probable and possible 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. Moreover, there can be no assurance that our reserves will ultimately be produced or that our proved undeveloped, probable and possible reserves will be developed within the periods anticipated. Any significant variance in the assumptions could materially affect the estimated quantity and value of our reserves.

Investors should not assume that the pre-tax net present value of our proved, probable and possible reserves is the current market value of our estimated oil and natural gas reserves. We base the pre-tax net present value of future net cash flows from our proved, probable and possible reserves on prices and costs on the date of the estimate. Actual future prices, costs, and the volume of produced reserves may differ materially from those used in the pre-tax net present value estimate.

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### ***We may not correctly evaluate reserves data or the exploitation potential of properties as we engage in our acquisition, development, and exploitation activities.***

Our future success will depend on the success of our acquisition, development, and exploitation activities. Our decisions to purchase, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Our estimates regarding reserves and production resulting from the acquisitions of TEMI, Talon Exploration, Amity, Petrogas, Direct Bulgaria and TBNG and our exploration and development activities may prove to be incorrect, which could significantly reduce our income and our ability to generate cash needed to fund our capital program and other working capital requirements in the longer term.

### ***We may be unable to acquire or develop additional reserves, which would reduce our cash flow and income.***

In general, production from oil and natural gas properties declines over time as reserves are depleted, with the rate of decline depending on reservoir characteristics. If we are not successful in our exploration and development activities or in acquiring properties containing reserves, our reserves will generally decline as reserves are produced. Our oil and natural gas production is highly dependent upon our ability to economically find, develop or acquire reserves in commercial quantities.

To the extent cash flow from operations is reduced, either by a decrease in prevailing prices for oil and natural gas or an increase in finding and development costs, and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired. Even with sufficient available capital, our future exploration and development activities may not result in additional reserves, and we might not be able to drill productive wells at acceptable costs.

### ***A substantial or extended decline in oil and natural gas prices may adversely affect our ability to meet our capital expenditure obligations and financial commitments.***

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, oil and natural gas. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future.

A decrease in oil or natural gas prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the value of these assets. If oil or natural gas prices decline significantly for extended periods of time in the future, we might not be able to generate sufficient cash flow from operations to meet our obligations and make planned capital expenditures. Oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. Among the factors that could cause fluctuations are:

- market expectations regarding supply and demand for oil and natural gas;
- levels of production and other activities of the Organization of Petroleum Exporting Countries and other oil and natural gas producing nations;
- market expectations about future prices;
- the level of global oil and natural gas exploration, production activity and inventories;
- political conditions, including embargoes, in or affecting oil and natural gas production activities; and
- the price and availability of alternative fuels.

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Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural gas prices may have a material adverse effect on our business, financial condition and results of operations.

***If oil and natural gas prices decline, we may be required to write down the carrying values of our oil and natural gas properties.***

There is a risk that we could be required to write down the carrying value of our oil and natural gas properties, which would reduce our earnings and shareholders' equity. We follow the successful efforts method of accounting for our oil and natural gas properties. Under this method, the costs of productive wells, developmental dry holes and productive leases are capitalized. The acquisition costs of unproved acreage are initially capitalized and are carried at cost, net of accumulated impairment provisions, until such leases are transferred to proved properties or charged to exploration expense as impairments of unproved properties. Exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged to expense as incurred. Exploratory drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to exploration expense if and when the well is determined to be non-productive. The capitalized costs of our oil and natural gas properties may not exceed their estimated fair market value. When evaluating our proved properties, we are required to test for potential write-downs at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets, which is typically on a field-by-field basis. If capitalized costs exceed future cash flows, we write down the costs of proved properties to our estimate of fair market value, which is generally estimated using a discounted cash flow approach. When evaluating our unproved properties, we write down the capitalized costs of the unproved properties if it is determined that the costs are not likely to be recoverable. Any such charge will not affect our cash flow from operating activities, but will reduce our earnings and shareholders' equity.

***The development of proved undeveloped reserves is uncertain. In addition, there are no assurances that our probable and possible reserves will be converted to proved reserves.***

At December 31, 2013, approximately 45.9% of our total estimated net proved reserves were proved undeveloped reserves. Undeveloped reserves, by their nature, are significantly less certain than developed reserves. At December 31, 2013, we also had a significant amount of unproved reserves, which consist of probable and possible reserves. There is significant uncertainty attached to unproved reserves estimates. The discovery, determination and exploitation of undeveloped or unproved reserves requires significant capital expenditures and successful drilling and exploration programs. We may not be able to raise the additional capital that we need to develop these reserves. There is no certainty that we will be able to convert undeveloped reserves to developed reserves or unproved reserves into proved reserves or that our undeveloped or unproved reserves will be economically viable or technically feasible to produce.

***Part of our strategy involves drilling in new or emerging unconventional formations using fracture stimulation and horizontal drilling and completion techniques. The results of our planned drilling program in these formations may be subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production.***

The results of our drilling in new or emerging unconventional formations, such as the Mezardere formation, are generally more uncertain than drilling results in areas that are developed and have established production. Because new or emerging formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Further, part of our drilling strategy to maximize recoveries from our properties in Turkey, particularly in the Thrace Basin and southeastern Turkey, involves the drilling of horizontal wells. Our experience with horizontal drilling in the Thrace Basin and southeastern Turkey, as well as the industry's drilling and production history, while growing, is limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and

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production profiles are better established. Further, the utilization of these techniques requires substantially greater capital expenditures, as compared to the drilling of a traditional vertical well. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, and/or natural gas and oil prices decline, our investment in these areas may not be as attractive as we anticipate and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

### ***Legislative and regulatory initiatives and increased public scrutiny relating to fracture stimulation activities could result in increased costs and additional operating restrictions or delays.***

Fracture stimulation is an important and commonly used process for the completion of oil and natural gas wells and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate production. Recently, there has been increased public concern regarding the potential environmental impact of fracture stimulation activities. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on drinking water supplies, the use of water in connection with completion operations, and the potential for impact to surface water, groundwater and the environment generally.

The increased attention regarding fracture stimulation could lead to greater opposition, including litigation, to oil and natural gas production activities using fracture stimulation techniques. Increased public scrutiny may also lead to additional levels of regulation in the countries in which we operate that could cause operational restrictions or delays, make it more difficult to perform fracture stimulation or could increase our costs of compliance and doing business. Additional legislation or regulation, such as a requirement to disclose the chemicals used in fracture stimulation, could make it easier for third parties opposing fracture stimulation to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. A substantial portion of our operations rely on fracture stimulation, and the adoption of legislation in Bulgaria and a temporary moratorium on unconventional drilling activities in Romania have placed restrictions on our fracture stimulation activities, causing us to suspend our fracture stimulation activities in Bulgaria and to relinquish our Sud Craiova license in Romania in 2013. The adoption of legislative or regulatory initiatives in Turkey restricting fracture stimulation could impose operational delays, increased operations costs and additional related burdens on our exploration and production activities which could suspend or make it more difficult to perform fracture stimulation, cause a material decrease in the drilling of new wells and related completion activities and increase our costs of compliance and doing business, which could materially impact our business and profitability.

### ***We are subject to operating hazards.***

The oil and natural gas exploration and production business involves a variety of operating risks, including the risk of fire, explosion, blowout, pipe failure, casing collapse, stuck tools, uncontrollable flows of oil or natural gas, abnormally pressured formations and environmental hazards such as oil spills, surface cratering, natural gas leaks, pipeline ruptures, discharges of toxic gases, underground migration, surface spills, mishandling of fracture stimulation fluids, including chemical additives, and natural disasters. The occurrence of any of these events could result in substantial losses to us due to injury and loss of life, loss of or damage to well bores and/or drilling or production equipment, costs of overcoming downhole problems, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Gathering systems and processing facilities are subject to many of the same hazards and any significant problems related to those facilities could adversely affect our ability to market our production.

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*Our oil and natural gas operations are subject to extensive and complex laws and government regulation in the jurisdictions in which we operate and compliance with existing and future laws may increase our costs or impair our operations.*

Our oil and natural gas operations are subject to numerous federal, state, local, foreign and provincial laws and regulations, including those related to the environment, employment, immigration, labor, oil and natural gas exploration and development, payments to local, foreign and provincial officials, taxes and the repatriation of foreign earnings. If we fail to adhere to any applicable federal, state, local, foreign and provincial laws or regulations, or if such laws or regulations restrict exploration or production, or negatively affect the sale, of oil and natural gas, our business, prospects, results of operations, financial condition or cash flows may be impaired. We may be subject to governmental sanctions, such as fines or penalties, as well as potential liability for personal injury, property or natural resource damage and might be required to make significant capital expenditures to comply with federal, state or international laws or regulations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations could adversely affect our business or operations, or substantially increase our costs and associated liabilities.

In addition, exploration for, and exploitation, production and sale of, oil and natural gas in each country in which we operate is subject to extensive national and local laws and regulations requiring various licenses, permits and approvals from various governmental agencies. If these licenses or permits are not issued or unfavorable restrictions or conditions are imposed on our exploration or drilling activities, we might not be able to conduct our operations as planned. Alternatively, failure to comply with these laws and regulations, including the requirements of any licenses or permits, might result in the suspension or termination of operations and subject us to penalties. Our costs to comply with these numerous laws, regulations, licenses and permits are significant.

Specifically, our oil and natural gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the imposition of administrative, civil and/or criminal penalties, incurring investigatory or remedial obligations and the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to comply in all material respects with applicable environmental laws and regulations, we cannot assure you that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability. We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations.

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In addition, many countries have agreed to regulate emissions of “greenhouse gases.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning of oil and natural gas, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for some of our services or products in the future.

***We do not plan to insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and natural gas operations.***

We do not intend to insure against all risks. Our oil and natural gas exploration and production activities are subject to numerous hazards and risks associated with drilling for, producing and transporting oil and natural gas, and storing, transporting and using explosive materials, and any of the following risks can cause substantial losses:

- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination, underground migration and surface spills or mishandling of fracture stimulation fluids, including chemical additives;
- abnormally pressured formations;
- leaks of oil, natural gas and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, including fracture stimulation activities, or from the gathering and transportation of oil, natural gas and other hydrocarbons, malfunctions of pipelines, processing or other facilities in our operations or at delivery points to third parties;
- spillage or mishandling of oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third-party service providers;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

As is customary in the oil and natural gas industry, we maintain insurance against some, but not all, of our operating risks. Our insurance may not be adequate to cover potential losses or liabilities and insurance coverage may not continue to be available at commercially acceptable premium levels or at all. We might not elect 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 or under-insured events could require us to make large unbudgeted cash expenditures that could adversely impact our business, financial condition or results of operations.

***We might not be able to identify liabilities associated with properties or obtain protection from sellers against them, which could cause us to incur losses.***

Our review and evaluation of prospects and future acquisitions might not necessarily reveal all existing or potential problems. For example, inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, may not be readily identified even when an inspection is undertaken. Even when problems are identified, a seller may be unwilling or unable to provide effective contractual protection against all or part of those problems, and we may assume environmental and other risks and liabilities in connection with acquired properties.

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***Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do, which may adversely affect our ability to compete.***

We operate in the highly competitive areas of oil and natural gas exploration, development, production and acquisition with a substantial number of other companies, including U.S.-based and foreign companies doing business in each of the countries in which we operate. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- seeking oil and natural gas exploration licenses and production licenses;
- acquiring desirable producing properties or new leases for future exploration;
- marketing oil and natural gas production;
- integrating new technologies; and
- contracting for drilling services and equipment and securing the expertise necessary to develop and operate properties.

Many of our competitors have substantially greater financial, managerial, technological and other resources than we do. These companies are able to pay more for exploratory prospects and productive oil and natural gas properties than we can. To the extent competitors are able to pay more for properties than we are paying, we will be at a competitive disadvantage. Further, many of our competitors enjoy technological advantages over us and may be able to implement new technologies more rapidly than we can. Our ability to explore for and produce oil and natural gas prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

***We might not be able to obtain necessary permits, approvals or agreements from one or more government agencies, surface owners, or other third parties, which could hamper our exploration, development or production activities.***

There are numerous permits, approvals, and agreements with third parties, which will be necessary in order to enable us to proceed with our exploration, development or production activities and otherwise accomplish our objectives. The government agencies in each country in which we operate have discretion in interpreting various laws, regulations, and policies governing operations under the licenses. Further, we may be required to enter into agreements with private surface owners to obtain access to, and agreements for, the location of surface facilities. In addition, because many of the laws governing oil and natural gas operations in the international countries in which we operate have been enacted relatively recently, there is only a relatively short history of the government agencies handling and interpreting those laws, including the various regulations and policies relating to those laws. This short history does not provide extensive precedents or the level of certainty that allows us to predict whether such agencies will act favorably toward us. The governments have broad discretion to interpret requirements for the issuance of drilling permits. Our inability to meet any such requirements could have a material adverse effect on our exploration, development or production activities.

### **Risks Related to Our Common Shares**

***The interests of our controlling shareholder may not coincide with yours and such controlling shareholder may make decisions with which you may disagree.***

As of March 1, 2014, Mr. Mitchell beneficially owned approximately 40% of our outstanding common shares. As a result, Mr. Mitchell could control substantially all matters requiring shareholder approval, including the election of directors and approval of significant corporate transactions. In addition, this concentration of ownership may delay or prevent a change in control of our company and make some future transactions more difficult or impossible without the support of Mr. Mitchell. The interests of Mr. Mitchell may not coincide with our interests or the interests of our other shareholders.

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### ***The value of our common shares may be affected by matters not related to our own operating performance.***

The value of our common shares may be affected by matters that are not related to our operating performance and which are outside of our control. These matters include the following:

- general economic conditions in the United States, Turkey, Bulgaria and globally;
- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and natural gas industry, including environmental regulation and regulation of fracture stimulation activities;
- fluctuation in foreign exchange or interest rates;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to obtain industry partner and other third-party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the need to obtain required approvals from regulatory authorities;
- worldwide supplies and prices of, and demand for, oil and natural gas;
- political conditions and developments in each of the countries in which we operate;
- political conditions in oil and natural gas producing regions;
- revenue and operating results failing to meet expectations in any particular period;
- investor perception of the oil and natural gas industry;
- limited trading volume of our common shares;
- announcements relating to our business or the business of our competitors;
- the sale of assets;
- our liquidity; and
- our ability to raise additional funds.

In the past, companies that have experienced volatility in the trading price of their common shares have been the subject of securities class action litigation. We might become involved in securities class action litigation in the future. Such litigation often results in substantial costs and diversion of management's attention and resources and could have a material adverse effect on our business, financial condition and results of operation.

### ***U.S. shareholders who hold common shares during a period when we are classified as a passive foreign investment company may be subject to certain adverse U.S. federal income tax consequences.***

Management believes that we are not currently a passive foreign investment company. However, we may have been a passive foreign investment company during one or more of our prior taxable years and could become a passive foreign investment company in the future. In general, classification of our company as a passive foreign investment company during a period when a U.S. shareholder holds common shares could result in certain adverse U.S. federal income tax consequences to such shareholder.

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*Certain U.S. shareholders who hold common shares during a period when we are classified as a controlled foreign corporation may be subject to certain adverse U.S. federal income tax rules.*

Management believes that we currently are a controlled foreign corporation for U.S. federal income tax purposes and that we will continue to be so treated. Consequently, a U.S. shareholder that owns 10% or more of the total combined voting power of all classes of our shares entitled to vote on the last day of our taxable year may be subject to certain adverse U.S. federal income tax rules with respect to the shareholder’s investment in us.

Item 1B. Unresolved Staff Comments

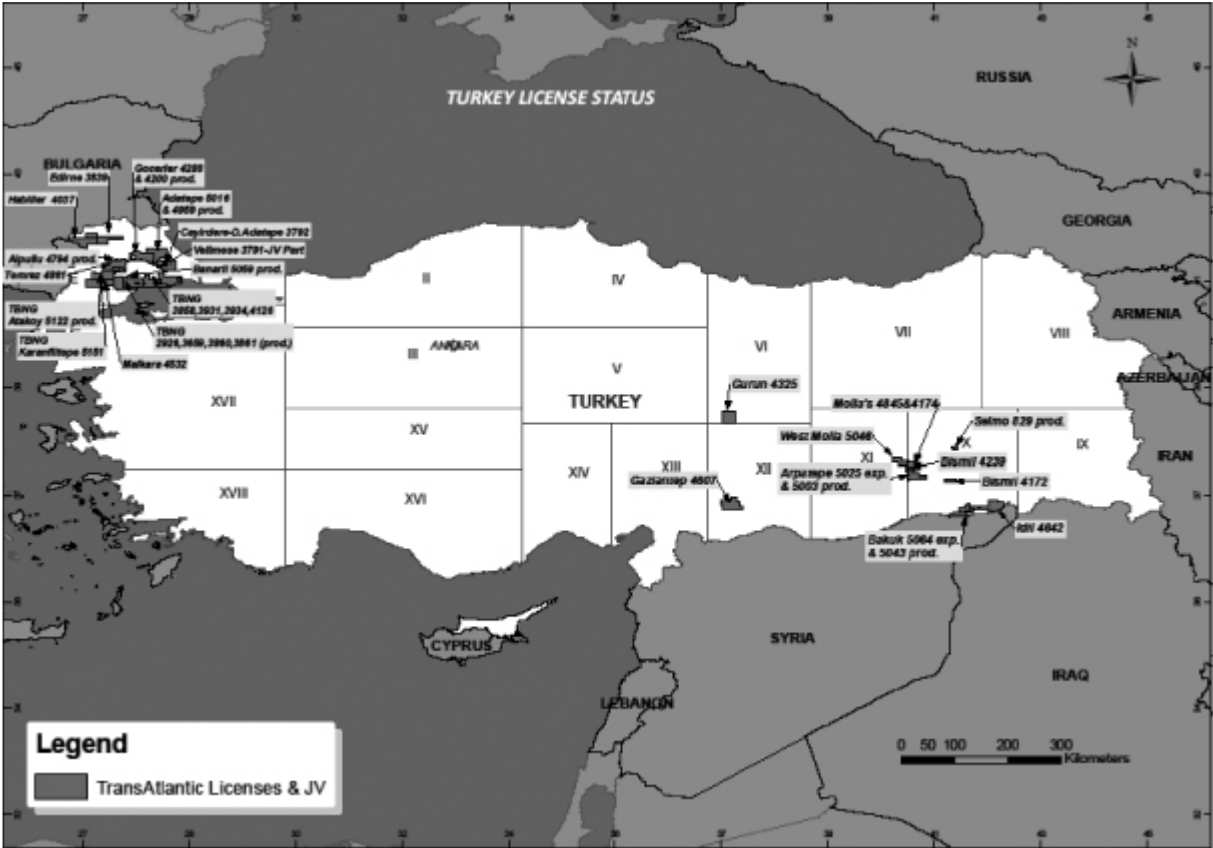
Not applicable.

Item 2. Properties

Turkey

**General.** As of March 1, 2014, we held interests in 23 onshore and offshore exploration licenses and 12 onshore production leases covering a total of approximately 2.1 million gross acres (approximately 1.3 million net acres) in Turkey. We acquired our interests in Turkey through acquisitions, as well as through farm-in agreements with existing third-party license holders and through applications submitted to the Turkish General Directorate for Petroleum Affairs (the “GDPA”), the agency responsible for the regulation of oil and natural gas activities under the Ministry of Energy and Natural Resources in Turkey.

The following map shows our interests in Turkey:



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**Reserves.** As of December 31, 2013, we had total net proved reserves of 9,714 Mbbl of oil and 15,039 Mmcf of natural gas, net probable reserves of 8,120 Mbbl of oil and 23,030 Mmcf of natural gas and net possible reserves of 16,877 Mbbl of oil and 78,205 Mmcf of natural gas in Turkey.

**Equipment Yards.** As of March 1, 2014, we leased equipment yards in Muratli, Diyarbakir and Tekirdag and owned equipment yards at Selmo and Edirne.

**Commercial Terms.** Turkey's fiscal regime for oil and natural gas licenses is presently comprised of royalties and income tax. The royalty rate is 12.5% and the corporate income tax rate is 20%. Our revenue from the Selmo oil field is subject to an additional 10% royalty, which is offset by the amount of exploration expense that TEMI and DMLP, the owners of our interest in the Selmo oil field, incur in Turkey. If those exploration expenses do not equal or exceed the amount of this additional 10% royalty, we would owe the difference. Dividends repatriated from Turkey would be subject to a withholding tax rate of 15% unless reduced by a tax treaty. There is also an 18% value added tax. However, for exploration licenses, no value added tax is assessed on drilling, completion, workover, seismic and geologic activities.

**Licensing Regime.** The licensing process in Turkey for oil and natural gas concessions occurs in three stages: permit, license and lease. Under a permit, the government grants the non-exclusive right to conduct a geological investigation over an area. The size of the area and the term of the permit are subject to the discretion of the GDPA. A new petroleum law was passed by the Turkish government in May 2013, amending some of the processes related to licensing and operations in Turkey. The regulations concerning implementation were passed by the Turkish government in January 2014. The existing licenses and future licensing processes are currently in a transition phase from the old petroleum law to the new petroleum law. The new law provides that operators have the option to maintain their licenses under the old petroleum law for the duration of the existing terms of a license or to convert their licenses to the new petroleum law prior to the expiration of the license. Further details regarding the process for conversion are awaiting confirmation from the GDPA.

The GDPA awards a license after it approves the applicant's work program, which may include obligations such as geological and geophysical work, seismic reprocessing and interpretation and contingent shooting of seismic and drilling of wells. A license grants exclusive rights over an area for the exploration for petroleum.

**Licensing Under the Old Petroleum Law.** A license has a term of four years and requires drilling activities by the third year, but this obligation may be deferred into the fourth year by posting a bond. A license is eligible for two separate two-year extensions by fulfilling prior work commitments and subscribing to additional work commitments. A final three-year term may be granted as an appraisal period for any oil or natural gas discovery registered in the previous terms. No single company may own more than an aggregate of 100% of eight licenses within a district. Rentals are due annually based on the size of the license.

Once a discovery is made, the license holder may apply to convert the area, not to exceed 25,000 hectares (approximately 62,000 acres), to a lease. Under a lease, the lessee may produce oil and natural gas. The term of a lease is for 20 years and may be extended for two further terms of 10 years each. Annual rentals are due based on the size of the lease. The production lease holder is typically able to apply for a new exploration license covering the area of the original exploration license, minus the area of the newly-granted production lease.

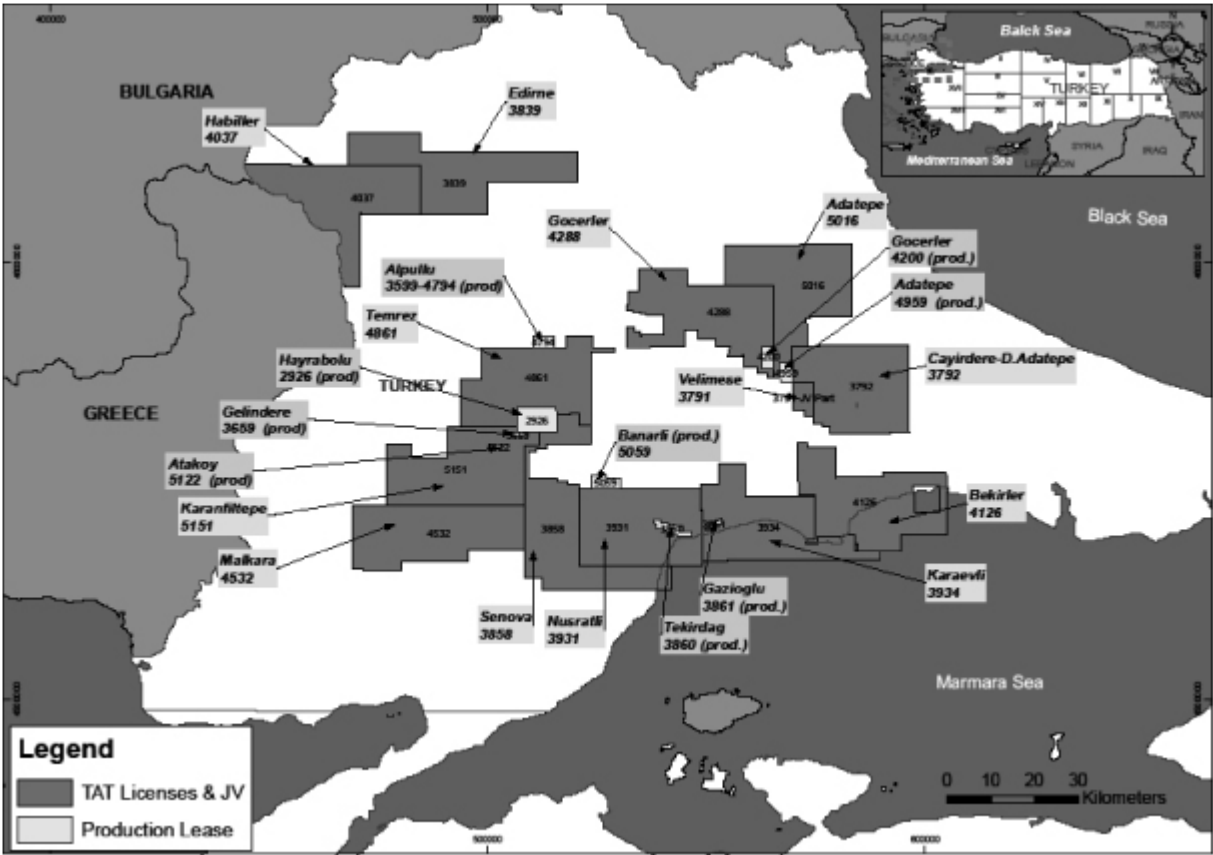
**Licensing Under the New Petroleum Law .** A license has a term of five years and requires the license holder to post a bond equal to 2% of the cost of the work commitments to secure the fulfillment of work commitments. Licenses shall be based on map sections of scale equal to 1/50,000 (approximately 148,000 acres) or 1/25,000 (approximately 37,000 acres). A license is eligible for two separate two-year extensions by fulfilling prior work commitments and subscribing to additional work commitments, including the drilling of at least one well in each separate extension period, and providing a bond to secure fulfillment of the additional work commitments. A final two-year term may be granted to appraise a petroleum discovery made during the prior terms. An additional six-month extension may be granted during any of the foregoing terms in order to complete the drilling or testing of an exploration well.

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Once a discovery is made, the license holder may apply to convert part of the license area, covering the prospective petroleum field, to a production lease. Under a lease, the lessee may produce oil and natural gas. The term of a lease is for 20 years and may be extended for two further terms of 10 years each if production is maintained. The production lease holder is typically able to apply for a new exploration license covering the area of the original exploration license, minus the area of the newly-granted production lease.

The expiration dates reported on our exploration licenses and production leases below are subject to various extensions available under the old petroleum law and the new petroleum law. Those portions of exploration licenses with production are available during any term for conversion to a production lease with a term of 20 years plus two further 10 year extensions if production is maintained. We are currently engaged in discussions with GDPA regarding the conversion of some of our qualifying acreage into the new petroleum law regulations. This will be a gradual process, but we anticipate that conversion into the new petroleum law will provide for the renewal of the exploration license terms for qualifying acreage.

**Northwestern Turkey.** The following map shows our interests in northwestern Turkey at March 1, 2014:



*Adatepe (Production Lease 4959 and License 5016).* We own a 50% working interest in Production Lease 4959 and License 5016, which cover approximately 3,086 gross acres and 117,000 gross acres, respectively. As of March 1, 2014, we had seven producing wells on the Adatepe production lease. In 2014, we plan to drill one well on License 5016 or License 4288 to satisfy the work program for License 5016, and we plan to maintain production to satisfy our obligation on Production Lease 4959. We are the operator of Production Lease 4959 and License 5016. The current terms of Production Lease 4959 and License 5016 expire in September 2031 and January 2017, respectively, with extensions available under the old and new petroleum laws.

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*Alpullu (Production Lease 4794) and Temrez (License 4861)*. We own a 100% working interest in Production Lease 4794 and License 4861, which cover approximately 3,158 acres and 117,000 acres, respectively. As of March 1, 2014, we had five producing wells on the Alpullu production lease. Two wells on License 4861 are currently awaiting completion, and the results of those operations will determine future drilling operations on the license. We plan to maintain production to satisfy our obligation on Production Lease 4794. We are the operator of Production Lease 4794 and License 4861, which expire in September 2028 and December 2014, respectively, with extensions available under the old and new petroleum laws.

*Atakoy (Production Lease 5122)*. We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 5122, which covers approximately 440 gross acres. As of March 1, 2014, we had six producing wells on the Atakoy production lease. We plan to maintain production to satisfy our obligation on Production Lease 5122. We are the operator of Production Lease 5122, which expires in November 2032, with extensions available under the old and new petroleum laws.

*Banarli (Production Lease 5059)*. We own a 50% working interest in Production Lease 5059, which covers approximately 4,609 gross acres. As of March 1, 2014, we had one producing well on the Banarli production lease. We plan to maintain production to satisfy our obligation on Production Lease 5059. We are the operator of Production Lease 5059, which expires in February 2032, with extensions available under the old and new petroleum laws.

*Bekirler (License 4126)*. We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 4126, which covers approximately 124,000 gross acres. We are the operator of License 4126, which expired in December 2013. In December 2013, the GDPA certified a gas discovery on the Bekirler license, and we subsequently applied for a three-year extension of License 4126 and are awaiting GDPA approval.

*Edirne (License 3839) and Habiller (License 4037)*. We own a 55% working interest in License 3839 and a 100% working interest in License 4037, which cover an aggregate of approximately 239,000 gross acres. In April 2010, we commenced natural gas sales from the Edirne natural gas field. As of March 1, 2014, we had 11 producing wells on the Edirne and Habiller licenses. We are the operator of Licenses 3839 and 4037, which expire in October 2014 and March 2016, respectively, with extensions available under the old and new petroleum laws. During 2014, we plan to submit an application for at least one production lease covering the productive areas on the Edirne license. Following the commercially successful application of minimum well concept drilling on these licenses in 2013, additional prospects are currently being evaluated for a similar drilling campaign in 2014.

*Gelindere (Production Lease 3659)*. We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 3659, which covers approximately 709 gross acres. As of March 1, 2014, we had one producing well on the Gelindere lease. We plan to maintain production to satisfy our obligation on Production Lease 3659. We are the operator of Production Lease 3659, which expires in June 2017, with extensions available under the old and new petroleum laws.

*Gocerler (Production Lease 4200 and License 4288)*. We own a 50% working interest in Production Lease 4200 and License 4288, which cover approximately 3,363 gross acres and 119,000 gross acres, respectively. As of March 1, 2014, we had three producing wells on the Gocerler production lease and seven producing wells on License 4288. We plan to drill one well in 2014 on License 4288 or License 5016 to satisfy the work program for License 4288 and we plan to maintain production to satisfy our obligations on Production Lease 4200. We are the operator of Production Lease 4200 and License 4288, which expire in March 2024 and August 2015, respectively, with extensions available under the old and new petroleum laws.

*Hayrabolu (Production Lease 2926)*. We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 2926, which covers approximately 12,400 gross acres. As of March 1, 2014,

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we had three producing wells on the Hayrabolu production lease. We plan to maintain production to satisfy our obligation on Production Lease 2926. We are the operator of Production Lease 2926, which expires in February 2020, with one ten-year extension available under the old and new petroleum laws.

*Karaevli (License 3934)* . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3934, which covers approximately 122,000 gross acres. As of March 1, 2014, we had three producing wells on the Karaevli license. We are the operator of License 3934, which expires in November 2015, with extensions available under the old and new petroleum laws.

*Karanfiltepe (License 5151)* . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 5151, which covers approximately 121,000 gross acres. We are the operator of the Karanfiltepe license, which expires in June 2017, with extensions available under the old and new petroleum laws.

*Malkara (License 4532)*. We own a 100% working interest in License 4532, which covers approximately 122,000 acres. We are the operator of License 4532, which expires in January 2015, with extensions available under the old and new petroleum laws.

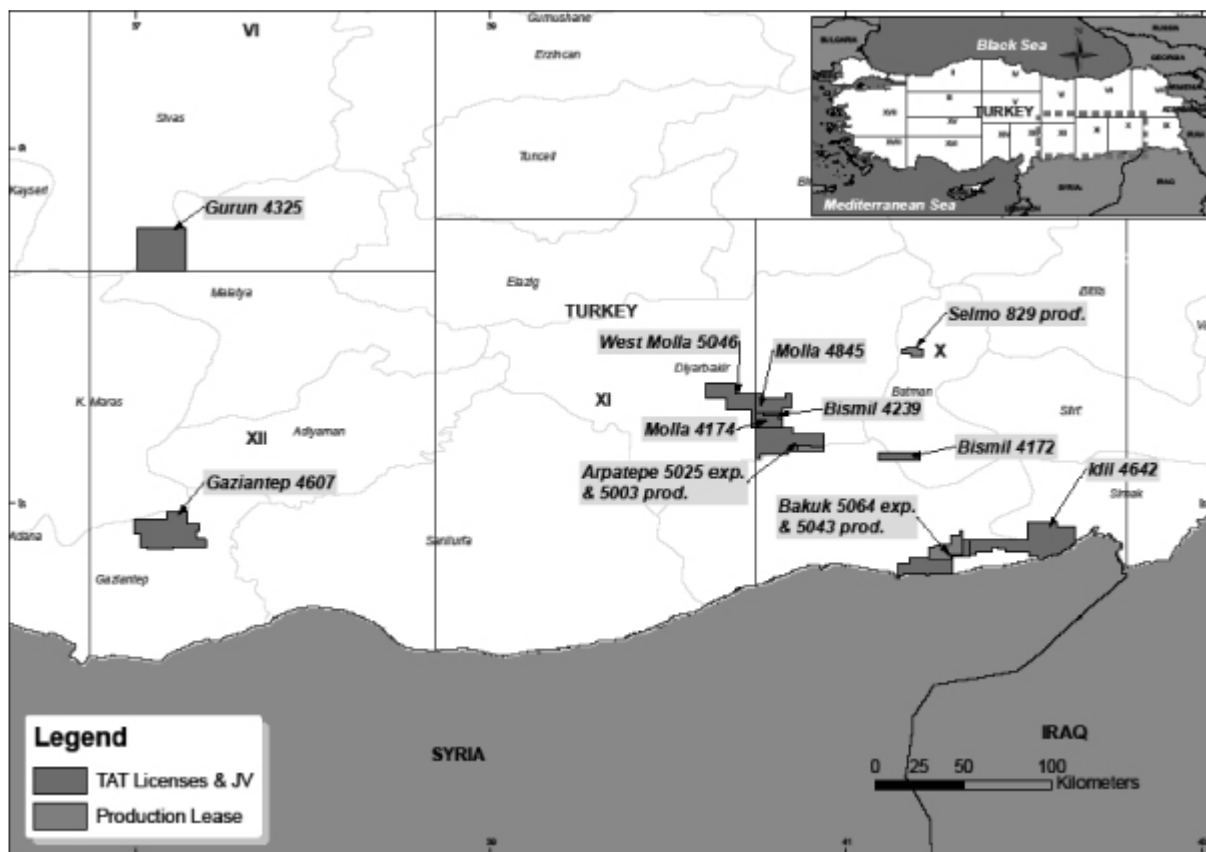
*Senova (License 3858)* . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3858, which covers approximately 122,000 gross acres. Depending on the production results of the Senova-1 well or successful recompletion efforts on additional wells, we plan to apply for a production lease on License 3858. We are the operator of License 3858, which expires in May 2015, with extensions available under the old and new petroleum laws.

*Tekirdag (Production Lease 3860), Gazioglu (Production Lease 3861) and Nusratli (License 3931)* . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Leases 3860 and 3861 and License 3931, which cover an aggregate of approximately 112,000 gross acres. As of March 1, 2014, we had 18 producing wells on the Tekirdag and Gazioglu production leases and 53 producing wells on the Nusratli license. Production Lease 3860 and License 3931 are the current focus of our 2014 horizontal drilling campaign in the Thrace Basin. We plan to maintain production to satisfy our obligation on Production Leases 3860 and 3861. We are the operator of Production Leases 3860 and 3861 and License 3931, which expire in December 2023, December 2021 and November 2015, respectively, with extensions available under the old and new petroleum laws.

*Velimese (License 3791) and Cayirdere (License 3792)*. We own a 50% working interest in Licenses 3791 and 3792, covering an aggregate of approximately 117,000 gross acres. As of March 1, 2014, we had four producing wells on License 3792. TPAO is the operator of Licenses 3791 and 3792, which expired in August 2013 and October 2013, respectively. In July 2013, we applied for a production lease on License 3792 and TPAO applied for a production lease on License 3791. After receipt of the production leases, we plan to negotiate the reacquisition of the remaining exploration acreage with TPAO on Licenses 3791 and 3792.

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**Southeastern Turkey.** The following map shows our interests in southeastern Turkey at March 1, 2014:



*Arpatepe (Production Lease 5003 and License 5025)* . We own a 50% working interest in Production Lease 5003 and License 5025, which cover approximately 11,200 and 84,600 gross acres, respectively. For 2013, our wellhead production of oil from the Arpatepe field was approximately 56,561 Bbls of oil, at an average rate of approximately 155 Bbl/d. As of March 1, 2014, we had five producing wells on the Arpatepe production lease. We plan to drill the Arpatepe-8 infill well in 2014, and a waterflood pilot is under evaluation for implementation in 2014. Aladdin Middle East, Ltd. is the operator of Production Lease 5003 and License 5025, which expire in November 2028 and February 2016, respectively, with extensions available under the old and new petroleum laws.

*Bakuk (License 5064 and Production Lease 5043)*. We own a 50% working interest in License 5064 and Production Lease 5043. The exploration license covers approximately 61,000 gross acres, and the production lease covers approximately 34,000 gross acres near the Turkish border with Syria. Production continues from the Bakuk-101 well, and we are evaluating additional offset well locations. Tiway Turkey, Ltd. (“Tiway”) is the operator of License 5064 and Production Lease 5043, which expire in June 2016 and January 2032, respectively, with extensions available under the old and new petroleum laws.

*Bismil (Licenses 4172 and 4239)* . Licenses 4172 and 4239 were acquired from ARAR during the second quarter of 2013. We own a 100% working interest in the ARAR licenses, which cover an aggregate of approximately 30,400 gross acres. License 4239 is a part of our large Molla 3D acquisition program and we are currently evaluating drilling prospects on the license for 2014. We are the operator of the licenses, which expire in June 2014 and December 2014, respectively, subject to establishing qualifying production and converting the acreage to a production lease or leases.

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*Gaziantep (License 4607)* . We own a 62.5% working interest in License 4607, subject to a 0.78% overriding royalty interest, which covers approximately 123,000 gross acres near the Turkish border with Syria. We are the operator of License 4607, which expired in August 2013. We are currently evaluating additional prospects on the Gaziantep license, including an offset to the Alibey-1H discovery well. We have applied for a two-year extension of the license and the application is pending with the GDPA. There are extensions available for License 4607 under the old and new petroleum laws.

*Gurun (License 4325)* . We own a 90% working interest in License 4325, which covers approximately 122,000 gross acres in central Turkey. We are the operator of License 4325, which expired in February 2014. We plan to negotiate for conversion of the license from the old petroleum law to the new petroleum law.

*Idil (License 4642)* . We own a 50% working interest in License 4642, which covers approximately 123,000 gross acres near the Turkish border with Syria. We plan to drill one well on this license in 2014. In February 2014, we entered into a farm-out agreement with Onshore whereby Onshore will fund the costs, up to \$3.5 million, to drill and complete a well targeting the Mardin formation. We plan to drill this well in 2014. We are the operator of License 4642, which expires in October 2014, with extensions available under the old and new petroleum laws.

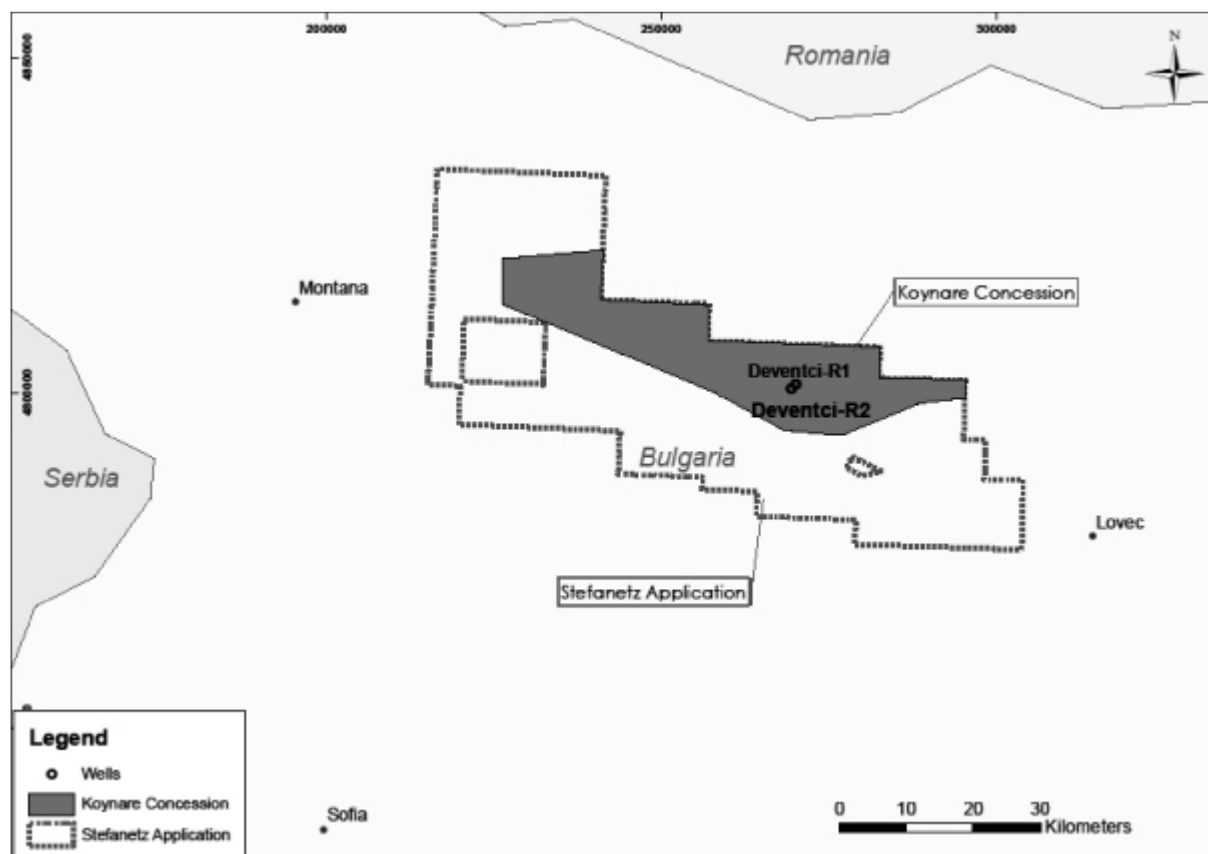
*Molla (Licenses 4174 and 4845) and West Molla (License 5046)* . We own a 100% working interest in Licenses 4174, 4845 and 5046, which cover an aggregate of approximately 112,000 acres adjacent to the northern border of our Production Lease 5003. In 2013, we drilled five horizontal wells in the Molla area. We continue to interpret the 800 sq. km. seismic data to delineate prospects on the Molla licenses, and we plan to sidetrack the Bahar-2 well following the interpretation of the data. We are the operator of Licenses 4174, 4845 and 5046, which expire in June 2014, March 2015 and June 2016, respectively, with extensions available under the old and new petroleum laws.

*Selmo (Production Lease 829)* . We own a 100% working interest in Production Lease 829, which covers 8,886 acres and includes the Selmo oil field. As of March 1, 2014, there were 50 producing wells on the Selmo production lease. For 2013, our wellhead production of oil in the Selmo field was approximately 670,711 Bbls of oil, at an average rate of approximately 1,838 Bbl/d. The Selmo lease is currently the focus of a horizontal drilling campaign, and we are evaluating a waterflood program for implementation in 2014. We are the operator of Production Lease 829, which expires in June 2015. We have submitted an application to extend the expiration date of Production Lease 829 until June 2025.

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### Bulgaria

**General.** As of March 1, 2014, we held interests in one onshore exploration permit and one onshore production concession in Bulgaria. We acquired all of our Bulgarian interests through the purchase of Direct Bulgaria in February 2011. In January 2012, the Bulgarian Parliament enacted legislation that banned the fracture stimulation of oil and natural gas wells in the Republic of Bulgaria. The legislation also had the effect of preventing conventional drilling and completion activities. In June 2012, the Bulgarian Parliament amended the legislation to clarify that conventional drilling and completion activities were not intended to be affected by the law. As long as this legislation remains in effect, our unconventional natural gas exploration, development and production activities in Bulgaria will be significantly constrained. The following map shows our interests in Bulgaria at March 1, 2014:



**Reserves.** As of December 31, 2013, there are no economic reserves associated with our properties in Bulgaria.

**Commercial Terms.** Bulgaria's petroleum laws provide a framework for investment and operation that allows foreign investors to retain the proceeds from the sale of petroleum production. The fiscal regime is comprised of royalties and income tax.

The royalty ranges from 2.5% to 30%, based on an "R factor" which is particular to each production concession agreement, but is typically calculated by dividing the total cumulative revenues from a production concession by the total cumulative costs incurred for that production concession.

The production concession holder pays Bulgarian corporate income tax, which is assessed at a rate of 10%. All costs incurred in connection with exploration, development and production operations are deductible for corporate income tax purposes.

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Resident companies which remit dividends outside of Bulgaria are subject to a dividend withholding tax between 10% to 15%, depending on the proportion of the capital owned by the recipient. No customs duty is payable on the export of petroleum, nor is customs duty payable on the import of material necessary to conduct petroleum operations. There is also a 20% value added tax. Oil is priced at market while natural gas is tied to a bundle pricing based in part on the import price and in part on the domestic price.

**Licensing Regime.** The licensing process in Bulgaria for oil and natural gas concessions occurs in two stages: exploration permit and then production concession.

Under an exploration permit, the government grants exploration rights for a term of up to five years to conduct seismic and other exploratory activities, including drilling. The recipient of an exploration permit commits to a work program and posts a bank guarantee in the amount of the estimated cost for the program. The area covered by an onshore exploration permit may be as large as 5,000 square kilometers. The exploration permit may be extended for up to two additional two-year terms, subject to fulfillment of minimum work programs, and may be extended for an additional one-year term in order to appraise potential geologic discoveries. Interests under an exploration permit are transferable, subject to government approval. The permit holder is required to pay an annual area fee equal to 30 Bulgarian Lev (approximately \$21 at March 1, 2014) per square kilometer, or 45 Bulgarian Lev (approximately \$32 at March 1, 2014) per square kilometer in the event the permit term is extended.

Upon the registration of a commercial discovery, an exploration permit holder may apply for a production concession. The production concession size corresponds to the area of the commercial discovery. The duration of a production concession is 35 years and may be extended by a further 15 years subject to the terms and conditions of the production concession agreement. Interests under a production concession are transferable, subject to government approval. No bonus is paid to the government by the company upon conversion to a production concession.

**Koynare.** We own a 100% working interest, subject to a 3.02% overriding royalty interest and KDL's 50% farm-in interest, in the Koynare production concession covering approximately 163,000 acres. The Koynare Concession Area contains the Deventci-R1 well, where we discovered a reservoir in the Jurassic-aged Ozirovo formation at a depth of approximately 13,800 feet, which the Bulgarian government has certified as a geologic and commercial discovery. In November 2011, we commenced drilling the Deventci-R2 appraisal well on the Koynare Concession Area, which we suspended following the enactment of the Bulgarian government's January 2012 legislation. During the second half of 2013, we resumed drilling the Deventci-R2 well and reached target depth of 14,100 feet in January 2014. The well is currently awaiting completion. We are the operator of the Koynare production concession, which expires in 2047.

**Stefenetz.** In November 2011, we initiated the application process for a production concession covering approximately 395,000 acres over the southern portion of our former A-Lovech exploration permit. The Stefenetz Concession Area is estimated to contain over 300,000 prospective acres for Etropole shale at a depth of approximately 12,500 feet, which the Bulgarian government has certified as a geologic discovery. During 2012, we initiated an environmental impact assessment, which the Bulgarian government must approve prior to granting the production concession.

In September 2011, we entered into an agreement with LNG pursuant to which LNG funded the drilling of an exploration well on the Stefenetz Concession Area to core and test the Etropole shale formation. This well, the Peshtene-R11, reached total depth in late November 2011, from which we collected more than 900 feet of core. We suspended drilling and completion of the Peshtene-R11 well following enactment of the Bulgarian government's January 2012 legislation. We and LNG are evaluating the core data and developing a conventional completion program for the Peshtene-R11 well. If we obtain a production concession over the Stefenetz Concession Area, LNG would fund up to an additional \$12.5 million in exchange for a 50% working interest in the production concession. The remaining 50% working interest in the production concession would be split equally between us and KDL.

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**Aglen.** We own a 100% working interest, subject to a 1% overriding royalty interest, in the Aglen exploration permit, which covers approximately 1,700 acres within the boundaries of the former A-Lovech exploration permit and lies within the boundary of the Stefenetz Concession Area. The Aglen permit contains a prospective deep natural gas field that produced approximately 9.0 Bcf of natural gas before being abandoned in the late 1990s. We are the operator of the Aglen permit, which was set to expire in April 2012. Due to the Bulgarian government's January 2012 legislation, a force majeure event was recognized by the government. As of March 1, 2014, we were negotiating the relinquishment of this license.

### Summary of Oil and Natural Gas Reserves

The following table summarizes our net proved, probable and possible reserves at December 31, 2013 in accordance with the rules and regulations of the SEC.

Reserves Category	Reserves		
	Oil and Condensate	Natural Gas	Total
	(Mbbbl)	(Mmcf)	(Mboe)
Proved Reserves			
Proved Developed	4,875	10,450	6,617
Proved Undeveloped	4,839	4,589	5,604
Total Proved	9,714	15,039	12,221
Probable Reserves	8,120	23,030	11,958
Possible Reserves	16,877	78,205	29,911

### Value of Proved Reserves

The following table shows our estimated future net revenue, PV-10 and Standardized Measure as of December 31, 2013:

<u>(in thousands)</u>	
Future net revenue	\$819,795
Total PV-10 <sup>(1)</sup>	\$592,524
Total Standardized Measure	\$495,769

- (1) The PV-10 value of the estimated future net revenue is not intended to represent the current market value of the estimated oil and natural gas reserves we own. Management believes that the presentation of PV-10, while not a financial measure in accordance with U.S. GAAP, provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of financial or operating performance under U.S. GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under U.S. GAAP. The Standardized Measure represents the PV-10 after giving effect to income taxes. The following table provides a reconciliation of our PV-10 to our Standardized Measure:

<u>(in thousands)</u>	
Total PV-10	\$ 592,524
Future income taxes	(127,971)
Discount of future income taxes at 10% per annum	31,216
Standardized Measure	<u>\$ 495,769</u>

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### Proved Reserves

Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. See “—Oil and Natural Gas Reserves under U.S. Law.”

At December 31, 2013, our estimated proved reserves were 12,221 Mboe, an increase of 5.4% compared to 11,597 Mboe at December 31, 2012. During 2013, we added estimated proved reserves of 2,005 Mboe through extensions and discoveries driven by our 2013 drilling activity in Turkey and 137 Mboe through performance revisions in existing producing wells. These increases were offset by sales volumes of 1,518 Mboe. The estimated undiscounted capital costs associated with our proved reserves is \$131.6 million.

### Proved Undeveloped Reserves

At December 31, 2013, our estimated proved undeveloped reserves were 5,604 Mboe, an increase of 10.0% compared to 5,094 Mboe at December 31, 2012. This increase in proved undeveloped reserves was primarily attributable to extensions and discoveries from horizontal drilling, improved well performance and successful recompletions.

### Probable Reserves

Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. See “—Oil and Natural Gas Reserves under U.S. Law.”

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

At December 31, 2013, our estimated probable reserves were 11,958 Mboe, an increase of 19.9% compared to 9,972 Mboe at December 31, 2012. This increase in probable reserves was primarily attributable to extensions and discoveries from horizontal drilling and improved well performance.

### Possible Reserves

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. See “—Oil and Natural Gas Reserves under U.S. Law.”

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When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

At December 31, 2013, our estimated possible reserves were 29,911 Mboe, a decrease of 8.3% compared to 32,608 Mboe at December 31, 2012. This decrease in possible reserves was primarily attributable to the transfer of possible reserves into proved and probable reserves.

### Internal Controls

Management has established, and is responsible for, a number of internal controls designed to provide reasonable assurance that the estimates of proved, probable and possible reserves are computed and reported in accordance with rules and regulations provided by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls consist of documented process workflows and qualified professional engineering and geological personnel with specific reservoir experience. We also retain an outside independent engineering firm to prepare estimates of our proved, probable and possible reserves. We work closely with this firm, and management is responsible for providing accurate operating and technical data to it. Management has tested the processes and controls regarding our reserves estimates for 2013. Senior management reviews and approves our reserves estimates, whether prepared internally or by third parties. In addition, our audit committee serves as our reserves committee and is composed of three outside directors, all of whom have experience in the review of energy company reserves evaluations. The audit committee reviews the final reserves estimate and also meets with representatives from the outside engineering firm to discuss their process and findings.

### Oil and Natural Gas Reserves under U.S. Law

In the United States, we are required to disclose proved reserves, and we are permitted to disclose probable and possible reserves, using the standards contained in Rule 4-10(a) of the SEC's Regulation S-X. The estimates of proved, probable and possible reserves presented as of December 31, 2013 have been prepared by DeGolyer and MacNaughton, our external engineers. The technical person at DeGolyer and MacNaughton that is primarily responsible for overseeing the preparation of our reserves estimates is a Registered Professional Engineer in the State of Texas and has a Bachelor of Science degree in Mechanical Engineering from Kansas State University. He has over 30 years of experience in oil and natural gas reservoir studies and evaluations and is a member of the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with DeGolyer and MacNaughton to ensure the integrity, accuracy and timeliness of data furnished to them for the preparation of their reserves estimates. Our chief reservoir engineer has over 42 years of experience in oil and natural gas reservoir studies and evaluations. He has a Bachelor of Science degree in Petroleum Engineering from Colorado School of Mines and a Masters of Business Administration degree from the University of Phoenix. He is a Registered Professional Engineer in the state of Colorado, and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

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Estimates of oil and natural gas reserves are projections based on a process involving an independent third-party engineering firm's collection of all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely upon various assumptions, including assumptions required by the SEC, such as constant oil and natural gas prices, operating expenses and future capital costs. We also make assumptions relating to availability of funds and timing of capital expenditures for development of our proved undeveloped, probable and possible reserves. These reports should not be construed as the current market value of our reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the reserves will ultimately be realized. Our actual results could differ materially. See "Supplemental Information —Supplemental oil and natural gas reserves information (unaudited)" to our consolidated financial statements for additional information regarding our oil and natural gas reserves.

The technologies and economic data used in the estimation of our proved, probable and possible reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

The estimates of proved, probable and possible reserves prepared by DeGolyer and MacNaughton for the year ended December 31, 2013 included a detailed review of our Selmo, Arpatepe, Bakuk, Molla and Thrace Basin properties in Turkey and our West Koynare field in Bulgaria. DeGolyer and MacNaughton determined that their estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about whether proved reserves are economically producible from a given date forward, under existing economic conditions, operating methods and government regulations, consistent with the definition in Rule 4-10(a)(24) of SEC Regulation S-X.

### **Oil and Natural Gas Reserves under Canadian Law**

As a reporting issuer under Alberta, British Columbia and Ontario securities laws, we are required under Canadian law to comply with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") implemented by the members of the Canadian Securities Administrators in all of our reserves related disclosures. DeGolyer and MacNaughton evaluated the Company's reserves as of December 31, 2013, in accordance with the reserves definitions of NI 51-101 and the Canadian Oil and Gas Evaluators Handbook ("COGEH"). Our annual oil and natural gas reserves disclosures prepared in accordance with NI 51-101 and COGEH and filed in Canada are available at [www.sedar.com](http://www.sedar.com).

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### Oil and Natural Gas Wellhead Production

The following table sets forth our wellhead production of oil and natural gas for 2013, 2012 and 2011:

Year	Wellhead Production		
	Oil <sup>(1)</sup> (Bbls)	Natural Gas (Mcf)	Total (Boe)
<b>2013</b>			
Turkey	941,297 <sup>(2)</sup>	3,915,898	1,593,946
Bulgaria	328	15,811	2,963
<b>2012</b>			
Turkey	952,309 <sup>(2)</sup>	4,419,017	1,688,812
Bulgaria	641	33,531	6,230
<b>2011</b>			
Turkey	894,836 <sup>(2)</sup>	4,821,199	1,698,369
Bulgaria	1,171	45,692	8,786

(1) "Oil" volumes include condensate (light oil) and medium crude oil.

(2) During 2013, 2012 and 2011, our wellhead production of oil in the Selmo oil field was 670,711 Bbls, 815,840 Bbls, and 840,584 Bbls, respectively.

### Oil and Natural Gas Sales Volumes

The following table sets forth our sales volumes of oil and natural gas for 2013, 2012 and 2011:

Year	Sales Volumes		
	Oil <sup>(1)</sup> (Bbls)	Natural Gas (Mcf)	Total (Boe)
<b>2013</b>			
Turkey	932,463 <sup>(2)</sup>	3,495,698	1,515,079
Bulgaria	328	15,811	2,963
<b>2012</b>			
Turkey	947,998 <sup>(2)</sup>	4,204,629	1,648,720
Bulgaria	641	33,531	6,230
<b>2011</b>			
Turkey	889,574 <sup>(2)</sup>	4,610,537	1,657,997
Bulgaria	1,171	45,692	8,786

(1) "Oil" volumes include condensate (light oil) and medium crude oil.

(2) During 2013, 2012 and 2011, our sales volumes in the Selmo oil field was 665,025 Bbls, 813,222 Bbls, and 838,615 Bbls, respectively.

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### Average Sales Price and Production Costs

The following table sets forth the average sales price per Bbl of oil and Mcf of natural gas and the average production cost, not including ad valorem and severance taxes, per unit of production for each of 2013, 2012 and 2011:

	2013	2012	2011
<b>Turkey</b>			
Average Sales Price			
Oil (\$/Bbl)	\$101.05	\$102.60	\$100.26
Natural Gas (\$/Mcf)	\$ 9.43	\$ 8.72	\$ 7.08
Unit Costs(1)			
Production (\$/Boe)	\$ 10.62	\$ 9.20	\$ 8.99
<b>Bulgaria</b>			
Average Sales Price			
Oil (\$/Bbl)	\$ 55.49	\$ 76.49	\$108.05
Natural Gas (\$/Mcf)	\$ 3.83	\$ 4.17	\$ 4.60
Unit Costs(1)			
Production (\$/Boe)	\$ 71.48	\$ 49.28	\$ 71.93

- (1) We have recalculated the oil and natural gas costs per Boe for the years ended December 31, 2012 and 2011 based on working interest volumes before royalty deductions to conform to current year presentation.

### Drilling Activity

The following table sets forth the number of net productive and dry exploratory wells and net productive and dry development wells we drilled in 2013, 2012 and 2011:

	Development Wells		Exploratory Wells	
	Productive	Dry	Productive	Dry
<b>Turkey</b>				
2013	10.51	0.50	3.50	4.42
2012	14.49	1.42	4.04	7.92
2011	14.54	5.50	2.55	6.60
<b>Bulgaria</b>				
2013	—	—	—	—
2012	—	—	—	—
2011	—	—	—	—

### Oil and Natural Gas Properties, Wells, Operations and Acreage

**Productive Wells.** The following table sets forth the number of productive wells (wells that were producing oil or natural gas or were capable of production) in which we held a working interest as of December 31, 2013:

	Oil		Natural Gas	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Turkey	61	57.9	130	63.1
Bulgaria	0	0	1	1

- (1) “Gross wells” means the wells in which we held a working interest (operating or non-operating).  
(2) “Net wells” means the sum of the fractional working interests owned in gross wells.

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**Developed Acreage.** The following table sets forth our total gross and net developed acreage as of December 31, 2013:

	Developed (Acres)	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>
Turkey	86,569	47,792

(1) “Gross” means the total number of acres in which we had a working interest.

(2) “Net” means the sum of the fractional working interests owned in gross acres.

**Undeveloped Acreage.** The following table sets forth our undeveloped land position as of December 31, 2013:

	Undeveloped (Acres)	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>
Turkey	1,979,091	1,238,970
Bulgaria	567,106	567,106
Total	2,546,197	1,806,076

(1) “Gross” means the total number of acres in which we had a working interest.

(2) “Net” means the sum of the fractional working interests owned in gross acres.

**Undeveloped Acreage Expirations.** The following table summarizes by year our undeveloped acreage scheduled to expire in the next five years:

As of December 31,	Undeveloped (Acres) <sup>(1)</sup>		% of Total Undeveloped
	Gross <sup>(2)</sup>	Net <sup>(3)</sup>	(Acres) <sup>(1)</sup> Net <sup>(3)</sup>
2014	529,995	402,469	22.3
2015	883,298	473,169	26.2
2016	445,072	313,231	17.3
2017	120,726	50,101	2.8
2018	—	—	—

(1) Excludes the Stefenetz Concession Area for which we have applied for a production concession.

(2) “Gross” means the total number of acres in which we had a working interest.

(3) “Net” means the sum of the fractional working interests owned in gross acres.

We anticipate that we will be able to extend the license terms for substantially all of our undeveloped acreage in Turkey scheduled to expire in 2014 through the execution of our current work commitments.

### Item 3. Legal Proceedings

TEMI has been involved in a number of lawsuits with a group of villagers living around the Selmo oil field who claim ownership of a portion of the surface at Selmo. These cases are being vigorously defended by TEMI and Turkish government authorities. We do not have enough information to estimate the potential additional operating costs we could incur in the event the purported surface owners’ claims are ultimately successful. The following is a summary of these cases.

In 2003, the villagers applied to the Kozluk Civil Court of First Instance in Turkey with seven title survey certificates dating back to Ottoman times. These villagers were granted title registration certificates, and in 2005, these villagers applied to the Kozluk Civil Court of First Instance to enlarge the areas covered by the certificates

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to approximately 20 square kilometers. Neither we nor, to our knowledge, any ministry in the Turkish government received notice of this court proceeding. Almost all of our production wells at the Selmo oil field lie within this enlarged area. In 2009, the Supreme Court overruled the Kozluk Civil Court of First Instance and directed it to re-examine the case (the “Surface Litigation”).

In 2006, the Turkish Forestry Authority filed a claim in the Kozluk Cadastre Court against the villagers for attempting to register land that is registered with the Turkish government as forest. TEMI joined the Turkish government as a plaintiff in that case. In February 2011, the Kozluk Cadastre Court decided to suspend the case until there is a resolution of the Surface Litigation.

In addition, TEMI is a defendant in two nuisance cases filed in the Kozluk Cadastre Court and one claim for damages filed in the Kozluk Civil Court of First Instance. The plaintiffs in each of these cases are the same villagers in the Surface Litigation. The Turkish Treasury Department and the Turkish Forestry Authority have joined TEMI as defendants in each of these cases. The Kozluk Cadastre Court has decided to suspend each of these nuisance cases until there is a resolution of the Surface Litigation. On December 27, 2012, the Kozluk Civil Court of First Instance dismissed the damages case, and the plaintiffs appealed that decision.

On June 27, 2012, the Kozluk Civil Court of First Instance dismissed the Surface Litigation. The court issued its formal decision on August 8, 2012, and the plaintiffs filed an appeal with the Court of Appeal. We will continue to vigorously defend our interests.

### Item 4. Mine Safety Disclosures

Not applicable.

## PART II

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

#### Canada

Our common shares are traded in Canada on the Toronto Stock Exchange (the “TSX”) under the trading symbol “TNP”. The following table sets forth the quarterly high and low sales prices per common share in Canadian dollars on the TSX for the periods indicated. The high and low sales prices per common share for each quarterly period within the two most recent fiscal years indicated below have been adjusted to reflect our 1-for-10 reverse stock split effected March 6, 2014.

	High	Low
2013:		
Fourth Quarter	\$10.00	\$ 7.70
Third Quarter	\$10.10	\$ 6.10
Second Quarter	\$ 9.40	\$ 7.10
First Quarter	\$10.70	\$ 8.50
2012:		
Fourth Quarter	\$10.20	\$ 7.00
Third Quarter	\$11.40	\$ 8.80
Second Quarter	\$12.70	\$ 8.60
First Quarter	\$16.10	\$10.80

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### United States

Our common shares are traded in the United States on the NYSE MKT exchange under the trading symbol “TAT”. The following table sets forth the high and low sales price per common share in U.S. Dollars on the NYSE MKT for the periods indicated. The high and low sales prices per common share for each quarterly period within the two most recent fiscal years indicated below have been adjusted to reflect our 1-for-10 reverse stock split effected March 6, 2014.

	<u>High</u>	<u>Low</u>
2013:		
Fourth Quarter	\$11.00	\$ 7.30
Third Quarter	\$ 9.70	\$ 7.10
Second Quarter	\$ 9.10	\$ 6.90
First Quarter	\$10.40	\$ 8.80
2012:		
Fourth Quarter	\$10.60	\$ 7.10
Third Quarter	\$12.00	\$ 8.40
Second Quarter	\$12.90	\$ 8.00
First Quarter	\$16.40	\$11.00

### Common Shares and Dividends

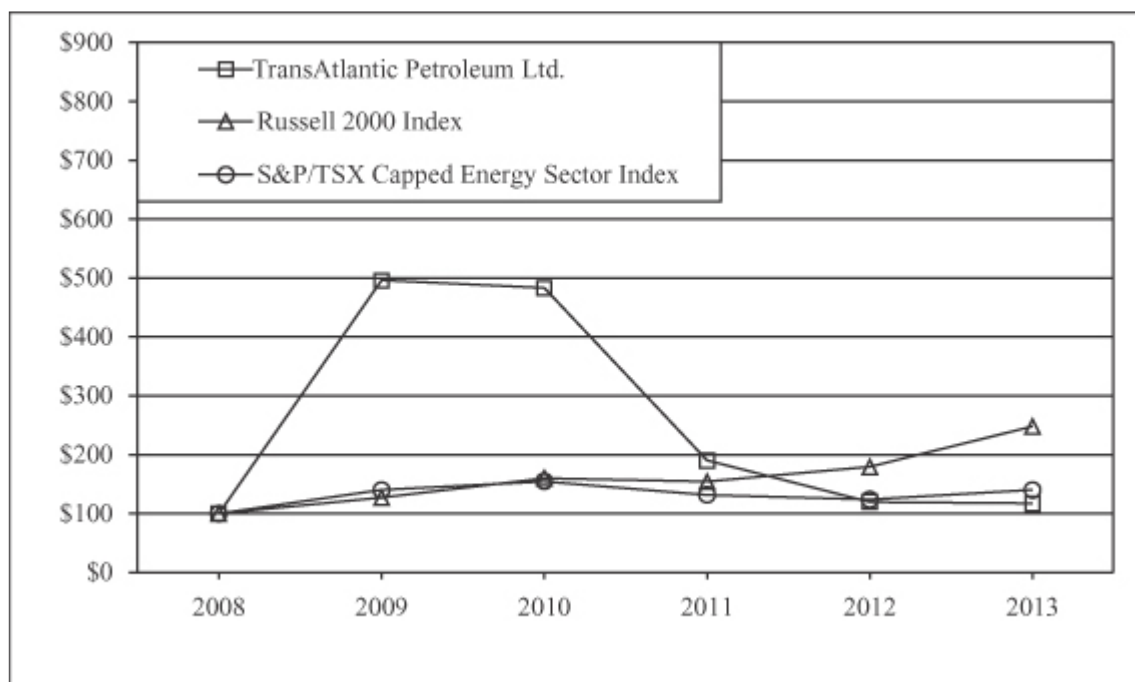
As of March 7, 2014, we had 37,402,698 common shares issued and outstanding and held by 332 record holders, including nominee holders such as banks and brokerage firms who hold shares for beneficial owners.

We have not declared any dividends to date on our common shares. We have no present intention of paying any cash dividends on our common shares in the foreseeable future, as we intend to use cash flow from operations to invest in our business.

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### Performance Graph

The following graph compares the cumulative total shareholder return on TransAtlantic Petroleum Ltd. common shares with the Russell 2000 Index and the S&P/TSX Capped Energy Sector Index. The graph assumes an investment of \$100 on December 31, 2008 in our common shares, the Russell 2000 Index and the S&P/TSX Capped Energy Sector Index, and assumes the reinvestment of dividends where applicable. The share price performance shown on the graph below is not intended and does not necessarily indicate future price performance.



Company/Index	2008	2009	2010	2011	2012	2013
TransAtlantic Petroleum Ltd.	\$100	\$496	\$483	\$190	\$120	\$117
Russell 2000 Index	\$100	\$127	\$160	\$154	\$179	\$248
S&P/TSX Capped Energy Sector Index	\$100	\$140	\$155	\$132	\$124	\$140

### Foreign Exchange Control Regulations

We have been designated as a non-resident for Bermuda exchange control purposes by the Bermuda Monetary Authority. Because of this designation, there are no restrictions on our ability to transfer funds in and out of Bermuda.

The transfer of shares between persons regarded as residents outside Bermuda for exchange control purposes and the sale of our common shares to or by such persons may take place without specific consent under the *Exchange Control Act 1972*. Issuances and transfers of shares involving any person regarded as a resident in Bermuda for exchange control purposes require specific approval under the *Exchange Control Act 1972*.

As an “exempted company,” we are exempt from Bermuda laws which restrict the percentage of share capital that may be held by non-Bermuda residents, but as an exempted company, we may not participate in certain business transactions, including: (1) the acquisition or holding of land in Bermuda (except that required for our business and held by way of lease or tenancy for terms of not more than 50 years) without the express authorization of the Bermuda legislature, (2) the taking of mortgages on land in Bermuda to secure an amount in

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excess of \$50,000 without the consent of the Minister of Finance, (3) the acquisition of any bonds or debentures secured by any land in Bermuda, other than certain types of Bermuda government securities or (4) the carrying on of business of any kind in Bermuda, except in furtherance of our business carried on outside Bermuda.

### Item 6. Selected Financial Data

The following table summarizes selected consolidated financial information from continuing operations for each of the five years in the period ended December 31, 2013. All periods presented have been adjusted to reflect our oilfield services business segment and Moroccan segment as discontinued operations. You should read the information set forth below in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(amounts in thousands, except per share amounts)				
Total revenues	\$130,827	\$143,908	\$ 128,905	\$ 70,854	\$ 27,748
Seismic and other exploration	14,009	5,040	11,542	16,883	14,602
Net loss from continuing operations	(13,271)	(6,373)	(77,574)	(29,545)	(40,061)
Comprehensive (loss) income	(50,686)	38,470	(173,012)	(77,514)	(52,545)
Basic and diluted net loss per common share from continuing operations	(0.36)	(0.17)	(2.18)	(0.95)	(1.89)
Basic and diluted weighted average number of shares outstanding	37,069	36,742	35,597	31,249	21,232

	As of December 31,				
	2013	2012	2011	2010	2009
	(amounts in thousands)				
Total assets	\$346,586	\$358,258	\$ 448,802	\$473,968	\$307,083
Long-term liabilities	63,619	72,819	112,904	62,486	13,341
Shareholders’ equity	167,317	213,827	171,273	276,057	264,607
Capital expenditures, including acquisitions(1)	99,951	81,824	152,440	170,317	92,359

(1) Excludes seismic and other exploration expenditures.

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

We are an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established, yet underexplored, petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2013, we held interests in approximately 1.9 million net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria. As of March 1, 2014, approximately 40% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, the chairman of our board of directors and our chief executive officer.

#### 2013 Financial and Operational Performance

- During 2013, we derived 74.1% of our oil and natural gas sales revenues from the production of oil and 25.9% from the production of natural gas.
- Total oil and natural gas sales revenues decreased to \$127.3 million for 2013 from \$134.1 million realized in 2012, excluding sales of purchased natural gas. The decrease was primarily the result of a decrease in sales volumes of 137 Mboe, which was partially offset by a \$2.80 per Boe increase in the average sales price received.
- Wellhead production decreased to 942 net Mbbl of oil and 3,932 net Mmcf of natural gas for 2013, compared to 953 net Mbbl of oil and 4,453 net Mmcf of natural gas for 2012.
- In 2013, we incurred \$114.0 million in total capital expenditures, including license acquisition, seismic and corporate expenditures, compared to \$87.7 million in 2012.
- At December 31, 2013, our debt outstanding was \$69.8 million.

#### Recent Developments

For information on our recent developments, see "Item 1. Business—Recent Developments."

#### Current Operations

During 2013, we implemented our three-part strategy to increase production and cash flow in Turkey: (i) the Molla horizontal program, (ii) the Selmo field redevelopment program, and (iii) the Thrace Basin development program. For additional information on our current operations, see "Item 1. Business—Current Operations."

#### Planned Operations

We continue to actively explore and develop our existing oil and natural gas properties in Turkey and Bulgaria. For more information on our planned 2014 operations, see "Item 1. Business—Planned Operations."

#### Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosures. Our significant accounting policies are described in "Note 2—Significant accounting policies" to our consolidated financial statements included in this Annual Report on Form 10-K. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. These estimates are based on historical experience, information received from third parties, and on various other assumptions that are believed to be reasonable under the circumstances,

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the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

We believe the following critical accounting policies affect the significant judgments and estimates used in the preparation of our consolidated financial statements.

**Oil and Natural Gas Properties.** In accordance with the successful efforts method of accounting for oil and natural gas properties, costs of productive wells, developmental dry holes and productive leases are capitalized into appropriate groups of properties based on geographical and geological similarities. Acquisition costs of proved properties are amortized using the unit-of-production method based on total proved reserves, and exploration well costs and additional development costs are amortized using the unit-of-production method based on proved developed reserves. Proceeds from the sale of properties are credited to property costs, and a gain or loss is recognized when a significant portion of an amortization base is sold or abandoned. Exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged to expense as incurred. Exploratory drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to exploration expense if and when the well is determined to be non-productive. The determination of an exploratory well's ability to produce must be made within one year from the completion of drilling activities. The acquisition costs of unproved acreage are initially capitalized and are carried at cost, net of accumulated impairment provisions, until such leases are transferred to proved properties or charged to exploration expense as impairments of unproved properties.

**Impairment of Long-Lived Assets.** We follow the provisions of Accounting Standards Codification ("ASC") 360, *Property, Plant and Equipment* ("ASC 360"). ASC 360 requires that our long-lived assets be assessed for potential impairment of their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. Proved oil and natural gas properties are evaluated by field for potential impairment. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of a field are less than its carrying value. If an impairment occurs, the carrying value of the impaired field is reduced to its estimated fair value, which is generally estimated using a discounted cash flow approach.

Unproved oil and natural gas properties do not have producing properties and are valued on acquisition by management, with the assistance of an independent expert when necessary. As reserves are proved through the successful completion of exploratory wells, the cost is transferred to proved properties. The cost of the remaining unproved basis is periodically evaluated by management to assess whether the value of a property has diminished. To do this assessment, management considers (i) estimated potential reserves and future net revenues from an independent expert, (ii) the Company's history in exploring the area, (iii) the Company's future drilling plans per its capital drilling program prepared by the Company's reservoir engineers and operations management, and (iv) other factors associated with the area. Impairment is taken on the unproved property value if it is determined that the costs are not likely to be recoverable. The valuation is subjective and requires management to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual results.

**Business Combinations.** We follow ASC 805, *Business Combinations* ("ASC 805"), and ASC 810-10-65, *Consolidation* ("ASC 810-10-65"). ASC 805 requires most identifiable assets, liabilities, non-controlling interests, and goodwill acquired in a business combination to be recorded at "fair value." The statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under ASC 805, all business combinations will be accounted for by applying the acquisition method.

**Foreign Currency Translation and Remeasurement.** We follow ASC 830, *Foreign Currency Matters* ("ASC 830") which requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. The functional currency for each of our subsidiaries in

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Turkey and Bulgaria is the local currency. For certain entities, translation adjustments result from the process of translating the functional currency of the foreign operation's financial statements into our U.S. Dollar reporting currency, which is a non-cash transaction. These translation adjustments are reported separately and accumulated in the consolidated balance sheets as a component of accumulated other comprehensive loss.

ASC 830 requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. Exchange gains or losses from re-measuring transactions and monetary accounts in a currency other than the functional currency are included in earnings.

**Goodwill.** In accordance with ASC 350, *Intangibles-Goodwill and Other* ("ASC 350"), goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise. ASC 350 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. We assessed the qualitative factors at December 31, 2013 and, based upon the results of the qualitative assessment, we determined that it was not necessary to perform the two-step goodwill impairment test and that our goodwill was not impaired. All of our goodwill is attributable to our Turkey operating segment.

### Other Recent Accounting Pronouncements and Reporting Rules

In February 2013, the Financial Accounting Standard Board ("FASB") issued Accounting Standards Update ("ASU") 2013-02, *New Disclosures for Items Reclassified Out of Accumulated Other Comprehensive Income* ("ASU 2013-02"). ASU 2013-02 requires reclassification adjustments for items that are reclassified out of accumulated other comprehensive income to net income to be presented in the statements where the components of net income and the components of other comprehensive income are presented or in the footnotes to the financial statements. Additionally, the amendment requires cross-referencing to other disclosures currently required for other reclassification items. The amendments were effective for interim and annual reporting periods beginning after December 15, 2012. We adopted the provisions of ASU 2013-02 as of January 1, 2013. The adoption of ASU 2013-02 did not have a material impact on our consolidated financial statements.

We have reviewed other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on our results of operations, financial position and cash flows. Based on that review, we believe that none of these recent pronouncements will have a significant effect on our current or future earnings or operations.

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### Results of Operations—Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Year Ended December 31, 2013	Year Ended December 31, 2012	Change 2013-2012
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
<b>Wellhead production:</b>			
Oil (Mbbl)	942	953	(11)
Natural gas (Mmcf)	3,932	4,453	(521)
Total production (Mboe)	1,597	1,695	(98)
Average daily wellhead production (Boepd)	4,375	4,631	(256)
<b>Sales volumes:</b>			
Oil (Mbbl)	933	949	(16)
Natural gas (Mmcf)	3,512	4,238	(726)
Total sales volumes (Mboe)	1,518	1,655	(137)
Average daily sales volumes (Boepd)	4,159	4,522	(363)
<b>Average sales prices:</b>			
Oil (per Bbl)	\$ 101.02	\$ 102.55	\$ (1.53)
Natural gas (per Mcf)	\$ 9.40	\$ 8.68	\$ 0.72
Oil equivalent (per Boe)	\$ 83.84	\$ 81.04	\$ 2.80
<b>Revenues:</b>			
Oil and natural gas sales	127,270	134,113	(6,843)
Sale of purchased natural gas	2,581	7,882	(5,301)
Other	976	1,913	(937)
Total revenues	130,827	143,908	(13,081)
<b>Costs and expenses:</b>			
Production	18,602	17,804	798
Exploration, abandonment and impairment	27,333	39,993	(12,660)
Cost of purchased natural gas	2,247	7,694	(5,447)
Seismic and other exploration	14,009	5,040	8,969
Revaluation of contingent consideration	(5,000)	—	(5,000)
General and administrative	29,020	33,947	(4,927)
Depletion	38,996	26,024	12,972
Depreciation and amortization	2,326	2,191	135
Interest and other expense	3,929	8,340	(4,411)
Foreign exchange loss (gain)	9,663	(1,083)	10,746
<b>Loss on commodity derivative contracts:</b>			
Cash settlements on commodity derivative contracts	(3,521)	(3,829)	308
Change in fair value on commodity derivative contracts	823	(1,719)	2,542
Total loss on commodity derivative contracts	(2,698)	(5,548)	2,850
<b>Oil and natural gas costs per Boe <sup>(1)</sup>:</b>			
Production	\$ 10.72	\$ 9.42	\$ 1.30
Depletion	\$ 22.48	\$ 13.77	\$ 8.71

- (1) We have recalculated the oil and natural gas costs per Boe for the year ended December 31, 2012 based on working interest volumes before royalty deductions to conform to current-year presentation.

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**Oil and Natural Gas Sales.** Excluding sales of purchased natural gas, total oil and natural gas sales decreased to \$127.3 million in 2013, from \$134.1 million in 2012. Of this decrease, \$11.1 million resulted from a decrease in sales volumes of 137 Mboe. Sales volumes decreased primarily on our Thrace Basin wells due to high decline rates. This decrease was partially offset by an increase of \$4.3 million, attributable to higher average realized prices per Boe resulting from the production of a higher percentage of oil and the realization of higher natural gas prices. Our average price received increased \$2.80 to \$83.84 per Boe in 2013, compared to \$81.04 per Boe in 2012.

**Production.** Production expenses for 2013 increased to \$18.6 million from \$17.8 million in 2012. The increase was primarily attributable to the sale of our oilfield services business in June 2012. Certain expenses that were classified as inter-company and eliminated upon consolidation prior to the sale are now classified as third party. Production expense per Boe increased \$1.30 to \$10.72 per Boe in 2013, compared to \$9.42 per Boe in 2012. This increase is primarily attributable to a decrease in our production volumes during 2013 as compared to 2012, combined with a higher percentage of oil production, which has a higher production cost per Boe compared to natural gas.

**Exploration, Abandonment and Impairment.** Exploration, abandonment and impairment costs decreased to \$27.3 million in 2013, compared to \$40.0 million for 2012. The decrease was primarily due to an \$8.7 million decrease in exploratory dry hole expense and a \$4.0 million decrease in impairment and abandonment. The majority of our impairment and abandonment charges of \$11.3 million in 2013 related to our exploration licenses in Turkey. In 2012, impairment was taken on a portion of our proved properties in Turkey for \$6.7 million and on our exploration licenses in Turkey for \$8.4 million. Additionally, in 2013, nine wells were written off to exploration, abandonment and impairment for \$16.0 million, compared to 16 wells which were written off in 2012 for \$24.7 million.

**Seismic and Other Exploration.** Seismic and other exploration costs increased to \$14.0 million for 2013, compared to \$5.0 million for 2012. The increase was primarily due to seismic acquisition activities conducted on our West Molla license during 2013.

**Revaluation of Contingent Consideration.** As a result of the Amendment to the Purchase Agreement with Direct, during 2013, we recognized the reversal of a \$5.0 million contingent liability that was originally recorded in 2011.

**General and Administrative.** General and administrative expense decreased \$4.9 million to \$29.0 million for 2013, compared to \$33.9 million for 2012. The decrease was primarily due to a decrease in employee-related costs of \$2.1 million and a decrease in legal, accounting and consultancy expense of \$0.5 million. Employee-related costs decreased due to a reduction in head count in 2013, and legal, accounting and consultancy expenses decreased primarily due to the timely filing of our quarterly reports on Form 10-Q for the quarters ended June 30, 2013 and September 30, 2013. Also contributing to the decrease was a \$2.0 million accrual for a contingency related to our Aglen exploration permit in Bulgaria, which was recognized during 2012. The remaining decrease of \$0.3 million was attributable to our overall cost reduction efforts.

**Depletion .** Depletion expense increased to \$39.0 million for 2013, compared to \$26.0 million in 2012. The increase was due primarily to capital additions in the Selmo, Tekirdag, Goksu and Molla fields and to downward reserves revisions, which increased the depletion rates for certain fields.

**Interest and Other Expense.** Interest and other expense decreased to \$3.9 million for 2013, compared to \$8.3 million for 2012. The decrease was primarily due to a decrease in our average debt levels from 2013 to 2012. In June 2012, we repaid \$129.2 million of debt with proceeds from the sale of our oilfield services business.

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**Foreign Exchange Loss (Gain).** We recorded a foreign exchange loss of \$9.7 million in 2013, compared to a gain of \$1.1 million in 2012. The change in foreign exchange is primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the New Turkish Lira (“TRY”) amount if it has not been settled previously. The increased foreign exchange loss in 2013 is due to a 19.7% decrease in value of the TRY compared to the U.S. Dollar in 2013.

**Loss on Commodity Derivative Contracts.** During 2013, we recorded a net loss on commodity derivative contracts of \$2.7 million, compared to a net loss of \$5.5 million for 2012. In 2013, we recorded a \$0.8 million gain to mark our commodity derivative contracts to their fair value and a \$3.5 million loss on settled contracts. In 2012, we recorded a \$1.7 million loss to mark our commodity derivative contracts to their fair value and a \$3.8 million loss on settled contracts. We are required under our Amended and Restated Credit Facility to hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey.

**Discontinued Operations.** All revenues and expenses associated with our Moroccan operations and oilfield services business for 2013 and 2012 have been included in discontinued operations. The results of operations for our Moroccan operations and oilfield services business were as follows:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
<b>Revenues:</b>		
Oil and natural gas sales	\$ —	\$ 68
Oilfield services	—	19,888
<b>Total revenues</b>	—	19,956
<b>Costs and expenses:</b>		
Production	178	789
Oilfield services costs	25	12,955
General and administrative	302	10,938
<b>Total costs and expenses</b>	505	24,682
<b>Operating loss</b>	(505)	(4,726)
<b>Other (expense) income:</b>		
Interest and other expense	(8)	(156)
Interest and other income	71	562
Foreign exchange (loss)	—	(763)
<b>Total other income (expense)</b>	63	(357)
<b>Loss before income taxes from discontinued operations</b>	(442)	(5,083)
Gain on disposal of discontinued operations	—	35,999
Income tax provision	—	(8,297)
<b>Net (loss) income from discontinued operations</b>	<u>\$ (442)</u>	<u>\$ 22,619</u>

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### Results of Operations—Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

	Year Ended December 31,		Change
	2012	2011	2012-2011
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
<b>Wellhead production:</b>			
Oil (Mbbl)	953	896	57
Natural gas (Mmcf)	4,453	4,867	(414)
Total production (Mboe)	1,695	1,707	(12)
Average daily wellhead production (Boepd)	4,631	4,677	(46)
<b>Sales volumes:</b>			
Oil (Mbbl)	949	891	58
Natural gas (Mmcf)	4,238	4,657	(419)
Total sales volumes (Mboe)	1,655	1,667	(12)
Average daily sales volumes (Boepd)	4,522	4,567	(45)
<b>Average sales prices:</b>			
Oil (per Bbl)	\$ 102.55	\$ 100.27	\$ 2.28
Natural gas (per Mcf)	\$ 8.68	\$ 7.05	\$ 1.63
Oil equivalent (per Boe)	\$ 81.04	\$ 74.48	\$ 6.56
<b>Revenues:</b>			
Oil and natural gas sales	134,113	124,162	9,951
Sale of purchased natural gas	7,882	2,668	5,214
Other	1,913	2,075	(162)
Total revenues	143,908	128,905	15,003
<b>Costs and expenses:</b>			
Production	17,804	18,475	(671)
Exploration, abandonment and impairment	39,993	60,952	(20,959)
Cost of purchased natural gas	7,694	2,645	5,049
Seismic and other exploration	5,040	11,542	(6,502)
Revaluation of contingent consideration	—	6,000	(6,000)
General and administrative	33,947	36,305	(2,358)
Depletion	26,024	37,004	(10,980)
Depreciation and amortization	2,191	2,004	187
Interest and other expense	8,340	13,665	(5,325)
Foreign exchange (gain) loss	(1,083)	11,973	(13,056)
<b>Loss on commodity derivative contracts:</b>			
Cash settlements on commodity derivative contracts	(3,829)	(4,854)	1,025
Change in fair value on commodity derivative contracts	(1,719)	(3,572)	1,853
Total loss on commodity derivative contracts	(5,548)	(8,426)	2,878
<b>Oil and natural gas costs per Boe <sup>(1)</sup>:</b>			
Production	\$ 9.42	\$ 9.49	\$ (0.07)
Depletion	\$ 13.77	\$ 19.01	\$ (5.24)

- (1) We have recalculated the oil and natural gas costs per Boe for the years ended December 31, 2012 and 2011 based on working interest volumes before royalty deductions to conform to current-year presentation.

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**Oil and Natural Gas Sales.** Excluding sales of purchased natural gas, total oil and natural gas sales increased to \$134.1 million in 2012, from \$124.2 million in 2011. Of this increase, \$10.8 million was the result of an increase in the average sales prices received and the sale of 58 additional Mbbl of oil in 2012. This increase was partially offset by a decrease of \$0.9 million attributable to a decrease in our sales volumes of 12 Mboe to 1,655 Mboe for 2012, compared to 1,667 Mboe in 2011. Sales volumes decreased primarily on our TBNG wells due to high decline rates and less drilling activity for the year ended December 31, 2012 compared to the same period in 2011. Our average sales price received for 2012 was \$81.04 per Boe, compared to \$74.48 per Boe for 2011.

**Production.** Production expenses for 2012 decreased to \$17.8 million from \$18.5 million in 2011.

**Exploration, Abandonment and Impairment.** Exploration, abandonment and impairment costs decreased to \$40.0 million in 2012, compared to \$61.0 million for 2011. The decrease was primarily due to the impairment of our Bulgarian properties of \$25.9 million in 2011 following the ban on fracture stimulation enacted by the Bulgarian Parliament in January 2012. Impairment for 2012 was taken on a portion of our proved assets in Turkey for \$6.7 million and on our exploration licenses in Turkey for \$8.4 million. In 2011, sixteen wells were written off to exploratory dry hole expense for \$26.8 million. Additionally, we recorded impairment of approximately \$18.8 million on our properties in Turkey in 2011, primarily driven by downward revisions in natural gas reserves in the Alpullu and Edirne fields. In 2012, 16 wells were written off for \$22.6 million, and a partial write-off of a well was expensed for \$2.1 million.

**Seismic and Other Exploration.** Seismic and other exploration expense decreased to \$5.0 million for 2012, compared to \$11.5 million for 2011. The decrease was due to a reduction in the number of seismic data acquisition projects from 28 in 2011 to eleven in 2012.

**Revaluation of Contingent Consideration.** During 2011, we determined that there was an increase in the likelihood that we may not be able to complete one of our drilling obligations required as part of the Purchase Agreement with Direct. Therefore, we increased our costs and expenses by \$6.0 million in 2011 to reflect our potential future costs. There were no contingent consideration costs required during 2012.

**General and Administrative.** General and administrative expense decreased \$2.4 million to \$33.9 million for 2012, compared to \$36.3 million for 2011, primarily due to reductions in employee-related costs of \$1.8 million, legal and accounting expenses of \$2.0 million, acquisition costs of \$1.2 million and travel costs of \$0.3 million. Employee-related costs decreased due to reductions in head count. Legal and accounting expenses were higher in the comparable period in 2011 due to the late filing of our Annual Report on Form 10-K for the year ended December 31, 2010 and our quarterly Report on Form 10-Q for the three months ended March 31, 2011. We had no acquisitions during the year ended 2012, compared to two acquisitions during the same period in 2011. This decrease was partially offset by increases of \$2.0 million for a contingency related to our Aglen exploration permit in Bulgaria and \$1.7 million as a result of TBNG being included for a full twelve months in 2012. The remaining decrease of \$0.8 million was attributable to our overall cost reduction efforts.

**Depletion.** Depletion expense decreased to \$26.0 million for 2012, compared to \$37.0 million in 2011. The decrease was due primarily to a reduction in our depletable basis in the Alpullu and Edirne fields, which was partially offset by additions in the Molla, Goksu and Tekirdag fields. The overall decrease was partially offset by downward reserves revisions and lower sales volumes, which increased the depletion rates for certain fields.

**Depreciation and Amortization.** Depreciation and amortization expense increased to \$2.2 million for 2012, compared to \$2.0 million in 2011.

**Interest and Other Expense.** Interest and other expense decreased to \$8.3 million for 2012, compared to \$13.7 million for 2011. The decrease was primarily due to the decrease in our outstanding debt. At December 31, 2012, our total outstanding debt was approximately \$32.8 million, compared to \$158.7 million at December 31, 2011.

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**Foreign Exchange (Gain) Loss .** We recorded a foreign exchange gain of \$1.1 million in 2012, compared to a loss of \$12.0 million in 2011. The change in foreign exchange is primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the TRY amount if it has not been settled previously. The change in foreign exchange is primarily due to the increase in value of the TRY compared to the U.S. Dollar in 2012.

**Loss on Commodity Derivative Contracts.** During 2012, we recorded a net loss on commodity derivative contracts of \$5.5 million, compared to a net loss of \$8.4 million for 2011. In 2012, we recorded a \$1.7 million loss to mark our commodity derivative contracts to their fair value and a \$3.8 million loss on settled contracts. In 2011, we recorded a \$3.6 million loss to mark our commodity derivative contracts to their fair value and a \$4.9 million loss on settled contracts. We are required under our Amended and Restated Credit Facility to hedge between 30% and 75% of our anticipated production volumes in the Selmo and Arpatpe oil fields in Turkey.

**Discontinued Operations.** All revenues and expenses associated with our Moroccan operations and oilfield services business for 2012 and 2011 have been included in discontinued operations. The results of operations for our Moroccan operations and oilfield services business were as follows:

	Year Ended December 31,	
	2012	2011
	(in thousands)	
<b>Revenues:</b>		
Oil and natural gas sales	\$ 68	\$ 217
Oilfield services	19,888	28,202
<b>Total revenues</b>	19,956	28,419
<b>Costs and expenses:</b>		
Production	789	928
Exploration, abandonment and impairment	—	23,163
Seismic and other exploration	—	67
Oilfield services costs	12,955	24,157
General and administrative	10,938	10,046
Depreciation, depletion and amortization	—	11,903
Accretion	—	1
<b>Total costs and expenses</b>	24,682	70,265
<b>Operating loss</b>	(4,726)	(41,846)
<b>Other (expense) income:</b>		
Interest and other expense	(156)	(474)
Interest and other income	562	116
Foreign exchange (loss) gain	(763)	3,090
<b>Total other (expense) income</b>	(357)	2,732
<b>Loss before income taxes from discontinued operations</b>	(5,083)	(39,114)
Gain on disposal of discontinued operations	35,999	—
Income tax provision	(8,297)	(4,255)
<b>Net income (loss) from discontinued operations</b>	<u>\$ 22,619</u>	<u>\$ (43,369)</u>

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### Capital Expenditures

For 2013, we incurred \$114.0 million in total capital expenditures, including license acquisition, seismic and corporate expenditures, compared to \$87.7 million for 2012. The increase in capital expenditures was primarily due to increased drilling and completion activities in the Selmo field and the seismic acquisition activities conducted in southeastern Turkey in 2013. We expect our net field capital expenditures for 2014, which includes seismic, to range between \$75.0 and \$100.0 million.

We expect net field capital expenditures during 2014 to consist of approximately \$76.0 million of drilling and completion expense for between 33 and 49 gross wells, \$4.0 million of seismic expense and \$8.5 million of infrastructure improvements and other capital investments. Of these expenditures, we expect to spend approximately 15% in northwestern Turkey, devoted to developing conventional and unconventional natural gas production and building infrastructure. Most of the remaining 85% of these anticipated expenditures is expected to be invested in southeastern Turkey, devoted to drilling developmental and exploratory oil wells at Selmo, Arpatepe and Molla and acquiring seismic data. We expect cash on hand, borrowings from our credit facilities, including our planned debt refinancing, and cash flow from operations will be sufficient to fund our 2014 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2014 capital expenditure budget is subject to change.

### Liquidity and Capital Resources

Our primary sources of liquidity for 2013 were our cash and cash equivalents and borrowings under our Amended and Restated Credit Facility and TBNG credit facility. At December 31, 2013, we had cash and cash equivalents of \$12.9 million, \$26.5 million in long-term debt, \$43.3 million in short-term debt and a working capital deficit of \$39.4 million (excluding assets and liabilities held for sale, deferred income taxes and derivative liabilities), compared to cash and cash equivalents of \$14.8 million, \$32.8 million in long-term debt, no short-term debt and working capital of \$10.6 million at December 31, 2012 (excluding assets and liabilities held for sale, deferred income taxes and derivative liabilities). Cash provided by operating activities from continuing operations during 2013 was \$68.8 million, compared to cash provided by operating activities from continuing operations of \$69.3 million in 2012.

Cash used in investing activities from continuing operations during 2013 increased to \$105.1 million, compared to cash used in investing activities from continuing operations of \$69.9 million in 2012, due primarily to higher additions to oil and natural gas properties and equipment and other properties in 2013. Additionally, cash provided by financing activities from continuing operations was \$37.0 million in 2013, compared to cash used in financing activities from continuing operations of \$125.7 million in 2012, due primarily to higher borrowings in 2013 and higher loan repayments in 2012.

As of December 31, 2013, the outstanding principal amount of our debt was \$69.8 million. In addition to cash, cash equivalents and cash flow from operations, at December 31, 2013, we had an Amended and Restated Credit Facility and a credit facility with a Turkish bank, both of which are discussed below.

*Amended and Restated Credit Facility*. DMLP, TEMI, Talon Exploration, TransAtlantic Turkey, Amity and Petrogas are Borrowers under the Amended and Restated Credit Facility. Each of the Borrowers is our wholly owned subsidiary. The Amended and Restated Credit Facility is guaranteed by TransAtlantic Petroleum Ltd. and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide.

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The amount drawn under the Amended and Restated Credit Facility may not exceed the lesser of (i) \$250.0 million, (ii) the borrowing base amount at such time, (iii) the aggregate commitments of all lenders at such time, and (iv) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender's individual commitment. At December 31, 2013, the lenders had aggregate commitments of \$67.5 million, with individual commitments of \$33.75 million each. On the last day of each fiscal quarter commencing December 31, 2013 and at the maturity date, the lenders' commitments are subject to reduction according to the following schedule:

<u>End of Period</u>	<u>Commitment Amount</u>
December 2013	\$67,500,000
March 2014	60,000,000
June 2014	52,000,000
September 2014	45,000,000
December 2014	37,500,000
March 2015	30,000,000
June 2015	22,500,000
September 2015	15,000,000
December 2015	7,500,000
March 2016	0

The borrowing base was re-determined semi-annually on April 1st and October 1st of each year prior to September 30, 2012, and is now re-determined quarterly on January 1st, April 1st, July 1st and October 1st of each year. Following our borrowing base redetermination on October 1, 2013, our borrowing base at December 31, 2013 was \$50.6 million. The borrowing base amount equals, for any calculation date, the lowest of:

- the debt value which results in the field life coverage ratio for such calculation date being 1.50 to 1.00;
- the debt value which results in the loan life coverage ratio for such calculation date being 1.30 to 1.00; and
- the debt value which results in a debt service coverage ratio for any calculation period being 1.25 to 1.00.

The Amended and Restated Credit Facility matures on the earlier of (i) May 18, 2016, or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual report of Standard Bank and the Borrowers determines that the aggregate amount of hydrocarbons to be produced from the borrowing base assets in Turkey are less than 25% of the amount of hydrocarbons to be produced from the borrowing base assets shown in the initial report prepared by Standard Bank and the Borrowers. The Amended and Restated Credit Facility bears various letter of credit sub-limits, including among other things, sub-limits of up to (i) \$10.0 million, (ii) the aggregate available unused and uncanceled portion of the lenders' commitments or (iii) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender's individual commitment.

Loans under the Amended and Restated Credit Facility accrue interest at a rate of three-month LIBOR plus 5.50% per annum (5.74% at December 31, 2013). The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.20% per annum of the unused and uncanceled portion of the aggregate commitments that is less than or equal to the maximum available amount under the Amended and Restated Credit Facility, and (b) 1.10% per annum of the unused and uncanceled portion of the aggregate commitments that exceed the maximum available amount under the Amended and Restated Credit Facility and is not available to be borrowed, (ii) on the date of issuance of any letter of credit, a fronting fee in an amount equal to 0.25% of the original maximum amount to be drawn under such letter of credit and (iii) a per annum letter of credit fee for each letter of credit issued equal to the face amount of such letter of credit

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multiplied by (a) 1.0% for any letter of credit that is cash collateralized or backed by a standby letter of credit issued by a financial institution acceptable to Standard Bank or (b) 5.50% for all other letters of credit.

The Amended and Restated Credit Facility is secured by a pledge of (i) the local collection accounts and offshore collection accounts of each of the Borrowers, (ii) the receivables payable to each of the Borrowers, (iii) the shares of each Borrower and (iv) substantially all of the present and future assets of the Borrowers.

The Borrowers are required to comply with certain financial and non-financial covenants under the Amended and Restated Credit Facility, including maintaining the following financial ratios during the four most recently completed fiscal quarters occurring on or after March 31, 2011:

- ratio of combined current assets to combined current liabilities of not less than 1.10 to 1.00;
- ratio of EBITDAX (less non-discretionary capital expenditures) to aggregate amounts payable under the Amended and Restated Credit Facility of not less than 1.50 to 1.00;
- ratio of EBITDAX (less non-discretionary capital expenditures) to interest expense of not less than 4.00 to 1.00; and
- ratio of total debt to EBITDAX of less than 2.50 to 1.00.

The Amended and Restated Credit Facility defines EBITDAX as net income (excluding extraordinary items) plus, to the extent deducted in calculating such net income, (i) interest expense (excluding interest paid-in-kind, or non-cash interest expense and interest incurred on certain subordinated intercompany debt or interest on equity recapitalized into subordinated debt), (ii) income tax expense, (iii) depreciation, depletion and amortization expense, (iv) amortization of intangibles and organization costs, (v) any extraordinary, unusual or non-recurring non-cash expenses or losses, (vi) expenses incurred in connection with oil and gas exploration activities entered into in the ordinary course of business (including related drilling, completion, geological and geophysical costs), (vii) transaction costs, expenses and fees incurred in connection with the negotiation, execution and delivery of the Amended and Restated Credit Facility and the related loan documents, and (viii) any other non-cash charges (including dry hole expenses and seismic expenses, to the extent such expenses would be capitalized), minus, to the extent included in calculating net income, (a) any extraordinary, unusual or non-recurring income or gains (including, gains on the sales of assets outside of the ordinary course of business) and (b) any other non-cash income or gains.

Pursuant to the terms of the Amended and Restated Credit Facility, until amounts under the Amended and Restated Credit Facility are repaid, each of the Borrowers shall not, and shall cause each of its subsidiaries not to, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of any Borrower or its subsidiaries to create any liens, (iii) enter into any merger, consolidation or amalgamation, liquidate or dissolve, (iv) dispose of any property or business, (v) pay any dividends, distributions or similar payments to shareholders, (vi) make certain types of investments, (vii) enter into any transactions with an affiliate, (viii) enter into a sale and leaseback arrangement, (ix) engage in any business or business activity, own any assets or assume any liabilities or obligations except as necessary in connection with, or reasonably related to, its business as an oil and natural gas exploration and production company or operate or carry on business in any jurisdiction outside of Turkey or its jurisdiction of formation, (x) change its organizational documents, (xi) permit its fiscal year to end on a day other than December 31st or change its method of determining fiscal quarters, or alter the accounting principles it uses, (xii) modify certain hydrocarbon licenses and agreements or material contracts, (xiii) enter into any hedge agreement for speculative purposes or (xiv) open or maintain new deposit, securities or commodity accounts.

An event of default under the Amended and Restated Credit Facility includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control is an event of default. A change of

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control is defined as the occurrence of any of the following: (i) our failure to own, of record and beneficially, all of the equity of the Borrowers or any Guarantor or to exercise, directly or indirectly, day-to-day management and operational control of any Borrower or Guarantor; (ii) the failure by the Borrowers to own or hold, directly or indirectly, all of the interests granted to Borrowers pursuant to certain hydrocarbon licenses designated in the Amended and Restated Credit Facility; or (iii) (a) Mr. Mitchell ceases for any reason to be the executive chairman of our board of directors at any time, (b) Mr. Mitchell and certain of his affiliates cease to own of record and beneficially at least 35% of our common shares; or (c) any person or group, excluding Mr. Mitchell and certain of his affiliates, shall become, or obtain rights to become, the beneficial owner, directly or indirectly, of more than 35% of our outstanding common shares entitled to vote for members of our board of directors on a fully-diluted basis. Provided that, if Mr. Mitchell ceases to be executive chairman of our board of directors by reason of his death or disability, such event shall not constitute an event of default unless we have not appointed a successor reasonably acceptable to the lenders within 60 days of the occurrence of such event.

Under the terms of the Amended and Restated Credit Facility, we are required to provide our audited consolidated financial statements for the year ended December 31, 2013 to the lenders by March 31, 2014, and we are required to provide the Borrowers' unaudited financial statements for the year ended December 31, 2013 to the lenders by April 30, 2014.

At December 31, 2013, the Borrowers had borrowed \$49.8 million under the Amended and Restated Credit Facility and had availability of \$0.8 million under the Amended and Restated Credit Facility. Pursuant to the Amended and Restated Credit Facility, TEMI entered into costless derivative contracts and three-way collar contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2013, 2014 and 2015. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk." If our borrowing base is increased in the future, we would be required under the Amended and Restated Credit Facility to hedge additional volumes of oil.

We are currently in the process of refinancing the Amended and Restated Credit Facility. In January 2014, we executed a mandate letter with two financial institutions. We expect to complete the refinancing in the second quarter of 2014. If we are unable to complete the refinancing of our Amended and Restated Credit Facility, we would curtail certain discretionary expenditures, and believe our resulting cash flow from operations and existing cash on hand are sufficient to conduct our operations through 2014 and meet our contractual obligations.

At December 31, 2013, we were not in compliance with Section 8.17(a) of our Amended and Restated Credit Facility, which requires the Borrowers to maintain a current ratio of not less than 1.10:1.0. The lenders have granted the Borrowers a waiver on the current ratio requirement through March 31, 2015.

*TBNG Credit Facility*. On June 18, 2013, TBNG entered into a 78.8 million TRY (approximately \$36.9 million at December 31, 2013) unsecured line of credit with a Turkish bank, of which 60 million TRY is available in cash for TBNG and 18.8 million TRY is available in the form of non-cash bank guarantees and letters of credit for TBNG and several other of our wholly owned subsidiaries operating in Turkey. The interest rate will be established at the time of each borrowing. We have made two borrowings under this credit facility, on October 9, 2013 and November 5, 2013, each of which has a one-year term at a fixed interest rate of 4.6% per annum. At maturity, we expect to renew the borrowings for one additional year at then current market interest rates. As of December 31, 2013, we had borrowed \$20.0 million under this credit facility.

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### Contractual Obligations

The following table presents a summary of our contractual obligations at December 31, 2013:

	Payments Due By Year						
	(in thousands)						
	Total	2014	2015	2016	2017	2018	Thereafter
Debt	\$69,766	\$43,284	\$20,740	\$5,742	\$ —	\$ —	\$ —
Leases and other	5,602	2,546	903	299	99	33	1,722
Total	<u>\$75,368</u>	<u>\$45,830</u>	<u>\$21,643</u>	<u>\$6,041</u>	<u>\$ 99</u>	<u>\$ 33</u>	<u>\$ 1,722</u>

### Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements at December 31, 2013.

### Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk from changes in interest rates, foreign currency exchange and hedging contracts. A discussion of the market risk exposures follows. Our market risk sensitive instruments were entered into for hedging and investment purposes, not for trading purposes.

#### Interest Rate Risk

At December 31, 2013, our exposure to interest rate changes related primarily to floating rate borrowings under our Amended and Restated Credit Facility. At December 31, 2013, we had \$49.8 million in outstanding borrowings under the Amended and Restated Credit Facility. The interest we pay on borrowings under the Amended and Restated Credit Facility is equal to three-month LIBOR plus 5.50% per annum (5.74% at December 31, 2013). A hypothetical 10% change in the interest rates we pay on the Amended and Restated Credit Facility as of December 31, 2013 would result in an increase or decrease in our interest costs of approximately \$0.3 million per year.

#### Foreign Currency Risk

We are subject to changes in foreign currency exchange rates as a result of our operations in foreign countries. The assets, liabilities and results of operations of our foreign operations are measured using the functional currency of such foreign operation. The functional currency for each of our subsidiaries in Turkey and Bulgaria is the local currency. As a result, translation adjustments will result from the process of translating the functional currency of our foreign operation's financial statements into the U.S. Dollar reporting currency, which is a non-cash transaction. Such non-cash translation adjustments accumulate on our consolidated balance sheets as a component of accumulated other comprehensive loss and are recorded in our consolidated statements of comprehensive income (loss).

The functional currency of our operations in Turkey and Bulgaria is the New Turkish Lira and the Bulgarian Lev, respectively. The exchange rates used to translate the financial position of our Turkish and Bulgarian operations at December 31, 2013, 2012 and 2011 are shown below:

	Year Ended December 31,		
	2013	2012	2011
New Turkish Lira per \$1.00 U.S. Dollar	2.1343	1.7826	1.8889
Bulgarian Lev per \$1.00 U.S. Dollar	1.4216	1.4827	1.5102

We are also subject to foreign currency exposures as a result of our operations in the other foreign countries in which we operate. We record foreign exchange (gain) loss on our consolidated statements of comprehensive

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income (loss) as a component of other (expense) income for gains and losses which result from re-measuring transactions and monetary accounts into our functional currency in earnings. The change in foreign exchange (gain) loss is primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the TRY amount if it has not been settled previously. For 2013 and 2012, we recorded a foreign exchange loss of \$9.7 million and a foreign exchange gain of \$1.1 million, respectively. We estimate that a 10% change in the exchange rates would impact such cash balances and our net loss by approximately \$0.8 million. We have not used foreign currency forward contracts to manage exchange rate fluctuations.

### Commodity Price Risk

Our revenues are derived from the sale of oil and natural gas. The prices for oil and natural gas are extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supplies, weather conditions, economic conditions and government actions.

Pursuant to our Amended and Restated Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with Standard Bank and BNP Paribas. As a result, TEMI has entered into costless collar and three-way collar derivative contracts with Standard Bank and BNP Paribas to hedge the price of oil. Pursuant to our Amended and Restated Credit Facility, we cannot enter into hedge agreements that, when aggregated with any other hydrocarbon hedge agreement then in effect, covers notional volumes in excess of 75% of the reasonably projected production volumes attributable to our proved developed reserves. The derivative contracts economically hedge against the variability in cash flows associated with the forecasted sale of our future oil production. While the use of the hedging arrangements will limit the downside risk of adverse price movements, it may also limit future gains from favorable movements.

The costless collars provide us with a lower limit “floor” price and an upper limit “ceiling” price on the hedged volumes. The floor price represents the lowest price we will receive for the hedged volumes while the ceiling price represents the highest price we will receive for the hedged volumes. The costless collars are settled monthly. These contracts may or may not involve payment or receipt of cash at inception, depending on the ceiling and floor pricing.

The three-way collar contracts consist of a purchased put, a sold call and a purchased call. The purchased put establishes a lower limit “floor” price, the sold call establishes an upper limit “ceiling” price and the purchased call establishes a “second floor” price on the hedged volumes. The three-way collar contracts require our counterparty to pay us if the settlement price for any settlement period is below the floor price. We are required to pay our counterparty if the settlement price for any settlement period is above the ceiling price but below the second floor price, and our counterparty is required to pay us if the settlement price for any settlement period is above the second floor price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. The three-way collar contracts are settled monthly.

We have elected not to designate our derivative financial instruments as hedges for accounting purposes, and accordingly, we record such contracts at fair value and recognize changes in such fair value in current earnings as they occur. We recognize gains and losses related to these contracts on a mark-to-market basis in our consolidated statements of comprehensive income (loss) under the caption “Loss on commodity derivative contracts.” Cash settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows. All of our oil derivative contracts are settled based upon Brent crude oil pricing. If commodity prices decrease, this commodity price change could have a positive impact to our earnings. Conversely, if commodity prices increase, this commodity price change could have a negative effect on our earnings. Each derivative contract is evaluated separately to determine its own fair value. During 2013, we recorded a net loss on commodity derivative contracts of \$2.7 million. We recorded a net loss on commodity derivative contracts of \$5.5 million in 2012.

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The following tables summarize our outstanding commodity derivatives contracts with respect to our future oil production as of December 31, 2013:

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Collar	January 1, 2014—December 31, 2014	622	\$ 80.83	\$ 118.07	\$ (387)
					<u>\$ (387)</u>
Type	Period	Collars		Additional Call	
		Quantity (Bbl/day)	Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Three-way collar contract	January 1, 2014— December 31, 2014	726	\$ 85.00	\$ 97.13	\$ (3,350)
Three-way collar contract	January 1, 2015— December 31, 2015	1,016	\$ 85.00	\$ 91.88	(4,320)
					<u>\$ (7,580)</u>

### Item 8. Financial Statements and Supplementary Data

See Index to Financial Statements on page F-1.

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

None.

### Item 9A. Controls and Procedures

#### Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is accumulated and communicated to management, including our chief executive officer and our chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2013, management carried out an evaluation, under the supervision and with the participation of our chief executive officer and chief financial officer, of the effectiveness of our disclosure controls and procedures. Based upon the evaluation, our chief executive officer and chief financial officer concluded that, as of December 31, 2013, our disclosure controls and procedures were not effective because of the material weaknesses described below.

#### Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the

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Exchange Act, is a process designed by, or under the supervision of, the chief executive officer and chief financial officer, or persons performing similar functions, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP and includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, (iii) provide reasonable assurance that receipts and expenditures are being made only in accordance with appropriate authorizations of management and the board of directors, and (iv) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Our management, under the supervision and with the participation of our chief executive officer and chief financial officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our internal control over financial reporting was not effective as of December 31, 2013 because of the identification of the material weaknesses identified below.

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement in our annual or interim financial statements will not be prevented or detected on a timely basis. We have identified the material weaknesses described below:

- We have not designed and implemented effective internal controls over the remeasurement and translation of our foreign subsidiaries' account balances. Specifically, we determined that controls over the selection of foreign currency rates used in the translation of the financial statements of our subsidiaries operating in Turkey, whose functional currency is the New Turkish Lira, were ineffective. As a result of this material weakness, management recorded adjustments to impairment expense, foreign exchange gain (loss), and foreign currency translation adjustment balances in our preliminary consolidated financial statements for the year ended December 31, 2013.
- We have not designed and implemented effective internal controls to sufficiently consider all information necessary to ensure proper classification and presentation within our consolidated financial statements. Specifically, controls over the proper classification of account balances and transactions within the consolidated balance sheet and statement of comprehensive income (loss), including gross as compared to net presentation, were not effectively designed. As a result of this material weakness, management recorded material classification adjustments in our preliminary consolidated financial statements for the year ended December 31, 2013, and management's determination of compliance with debt covenants was adversely affected.

As a result of these two material weaknesses, there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements, as stated in their reports on pages F-2 and F-3 of this Form 10-K.

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### Management's Plan for Remediation of Our Material Weaknesses

As a result of the errors in foreign currency translation, we have implemented a more comprehensive review of the impact of foreign currency rates in our review processes, starting in the first quarter of 2014. While improvements occurred throughout 2013, we continue to find errors related to the selection of foreign currency rates used in translating the financial statements of our subsidiaries operating in Turkey. Management expects remediation efforts in 2014 to continue to improve our internal control over financial reporting.

Many of the underlying causes of the ineffective controls over proper classification and presentation existed prior to 2013, and management has worked diligently to identify and properly account for these transactions in 2013. We expect to implement more specific controls over account balances which fluctuate between short and long-term, and within our account balances in the statement of comprehensive income (loss).

We expect to continue to automate and streamline accounting processes where possible, improve documentation and training and continue to monitor the performance of control activities in both our Istanbul, Turkey and Addison, Texas offices. Finally, we expect to implement a fully integrated SAP accounting system that will automate many of the manual calculations and tasks we currently perform in our financial closing process and that will include additional controls which will be built into the software in 2014. We expect to implement the new accounting system by the end of 2014.

In addition, our chief executive officer and chief financial officer plan to regularly meet with our senior accounting staff to monitor progress, identify continuing deficiencies and make any necessary adjustments to personnel or our plan to ensure the effective implementation of remedial measures.

While we believe that the above remediation plan will result in the remediation of our material weaknesses in 2014, there is no assurance that these efforts will be sufficient and that additional remedial efforts will not be necessary.

### Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2013, as discussed below, we implemented more robust and comprehensive management review procedures.

We reported six material weaknesses as of December 31, 2012. Because of significant remediation efforts made by management, the number of material weaknesses has been reduced to two as of December 31, 2013. Management has strengthened our internal control over financial reporting and focused on addressing and remediating the identified deficiencies in our processes which contributed to the material weaknesses identified in 2012. Our chief financial officer met regularly with our senior accounting staff to monitor the progress of our plan to ensure the effective implementation of remedial measures. During 2013, we developed and implemented more robust and comprehensive management review procedures, controls, desk manuals, and checklists as part of our internal control framework.

As of December 31, 2013, management has sufficient evidence to conclude that remediation has been completed for five of the material weaknesses which were reported as of December 31, 2012. However, based upon management's assessment of internal control over financial reporting as of December 31, 2013, management identified another material weakness related to classification and presentation, which arose during the fourth quarter of 2013.

There were no additional changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Item 9B. Other Information.

None.

**PART III**

**Item 10. Directors, Executive Officers and Corporate Governance**

Certain information required in response to this Item 10 is contained under the heading “Executive Officers of the Registrant” in Part I of this Annual Report on Form 10-K. Other information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act, not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

***Code of Business Conduct***

We have adopted a code of ethics that applies to all our officers, directors and employees, including our principal executive officer, principal financial officer, principal accounting officer and controller. The full text of our Code of Conduct is published on our website at [www.transatlanticpetroleum.com](http://www.transatlanticpetroleum.com), on the Corporate Governance page under the About tab. We intend to disclose future amendments to certain provisions of the Code of Conduct, or waivers of such provisions granted to executive officers and directors, on our website within four business days following the date of such amendment or waiver.

**Item 11. Executive Compensation**

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

**Item 14. Principal Accountant Fees and Services**

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

**PART IV**

**Item 15. Exhibits and Financial Statement Schedules**

(a) Documents filed as part of the Report.

1. [Reports of Independent Registered Public Accounting Firms](#)  
[Consolidated Balance Sheets as of December 31, 2013 and 2012](#)  
[Consolidated Statements of Comprehensive Income \(Loss\) for the years ended December 31, 2013, 2012 and 2011](#)  
[Consolidated Statements of Equity for the years ended December 31, 2013, 2012 and 2011](#)  
[Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011](#)  
[Notes to Consolidated Financial Statements](#)
2. Exhibits required to be filed by Item 601 of Regulation S-K

The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this report.

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### SIGNATURES

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

March 13, 2014

#### TRANSATLANTIC PETROLEUM LTD.

/ S / N. M ALONE M ITCHELL 3<sup>rd</sup>

**N. Malone Mitchell 3<sup>rd</sup>**  
**Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/S/ N. M ALONE M ITCHELL 3 <sup>rd</sup>	Chairman and Chief Executive Officer (Principal Executive Officer)	March 13, 2014
<b>N. Malone Mitchell 3<sup>rd</sup></b>		
/S/ W IL F. S AQUETON	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer/Controller)	March 13, 2014
<b>Wil F. Saqueton</b>		
/S/ B OB G. A LEXANDER	Director	March 13, 2014
<b>Bob G. Alexander</b>		
/S/ B RIAN E. B AYLEY	Director	March 13, 2014
<b>Brian Bayley</b>		
/S/ C HARLES J. C AMPISE	Director	March 13, 2014
<b>Charles J. Campise</b>		
/S/ M ARLAN W. D OWNEY	Director	March 13, 2014
<b>Marlan W. Downey</b>		
/S/ G REGORY K. R ENWICK	Director	March 13, 2014
<b>Gregory K. Renwick</b>		
/S/ M EL G. R IGGS	Director	March 13, 2014
<b>Mel G. Riggs</b>		

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**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors and Stockholders  
TransAtlantic Petroleum Ltd.

We have audited the accompanying consolidated balance sheets of TransAtlantic Petroleum Ltd. and subsidiaries (the Company) as of December 31, 2013 and 2012, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for each of the years in the two-year period then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the two-year period then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAtlantic Petroleum Ltd. and subsidiaries' internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 13, 2014 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas  
March 13, 2014

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors and Stockholders

TransAtlantic Petroleum Ltd.:

We have audited TransAtlantic Petroleum Ltd. and subsidiaries (the Company) internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO ). TransAtlantic Petroleum Ltd.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Annual Report on Internal Control Over Financial Reporting" appearing under Item 9A of the Company's December 31, 2013 Annual Report on Form 10-K. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. Management has identified and included the following material weaknesses in management's assessment:

- The Company has not designed and implemented effective internal controls over the remeasurement and translation of its foreign subsidiaries' account balances.
- The Company has not designed and implemented effective internal controls that sufficiently consider all information necessary to ensure proper classification and presentation within its consolidated financial statements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of comprehensive income (loss), equity,

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and cash flows for each of the years in the two-year period then ended. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2013 consolidated financial statements, and this report does not affect our report dated March 13, 2014, which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, because of the effect of the aforementioned material weaknesses on the achievement of the objectives of the control criteria, TransAtlantic Petroleum Ltd. and subsidiaries have not maintained effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/s/ KPMG LLP

Dallas, Texas  
March 13, 2014

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors and Stockholders

TransAtlantic Petroleum Ltd.:

We have audited the accompanying consolidated statements of comprehensive loss, equity and cash flows of TransAtlantic Petroleum Ltd. and subsidiaries (the “Company”) for the year ended December 31, 2011. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of TransAtlantic Petroleum Ltd. and subsidiaries for the year ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Calgary, Canada

March 23, 2012 (except Note 1 dated March 13, 2014)

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**TRANS ATLANTIC PETROLEUM LTD.**  
Consolidated Balance Sheets  
As of December 31, 2013 and 2012  
(in thousands of U.S. Dollars, except share data)

	<b>2013</b>	<b>2012</b>
<b>ASSETS</b>		
<b>Current assets:</b>		
Cash and cash equivalents	\$ 12,881	\$ 14,768
Accounts receivable		
Oil and natural gas sales, net	30,619	34,158
Joint interest and other, net	15,348	18,192
Related party	1,004	419
Prepaid and other current assets	5,072	2,339
Deferred income taxes	2,239	1,895
Assets held for sale	536	1,619
Total current assets	<u>67,699</u>	<u>73,390</u>
<b>Property and equipment:</b>		
Oil and natural gas properties (successful efforts method)		
Proved	260,857	231,498
Unproved	54,392	68,938
Equipment and other property	39,916	35,747
	<u>355,165</u>	<u>336,183</u>
Less accumulated depreciation, depletion and amortization	<u>(104,193)</u>	<u>(80,031)</u>
Property and equipment, net	250,972	256,152
<b>Other long-term assets:</b>		
Other assets	8,880	8,195
Note receivable – related party	11,500	11,500
Goodwill	7,535	9,021
Total other assets	<u>27,915</u>	<u>28,716</u>
<b>Total assets</b>	<u><b>\$ 346,586</b></u>	<u><b>\$ 358,258</b></u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current liabilities:</b>		
Accounts payable	\$ 16,712	\$ 12,864
Accounts payable – related party	23,090	15,634
Accrued liabilities	20,658	29,972
Derivative liabilities	3,737	3,908
Asset retirement obligations	610	818
Loan payable	43,284	—
Liabilities held for sale	7,559	8,416
Total current liabilities	<u>115,650</u>	<u>71,612</u>
<b>Long-term liabilities:</b>		
Asset retirement obligations	10,286	11,140
Accrued liabilities	6,487	7,548
Deferred income taxes	16,134	16,483
Loan payable	26,482	32,766
Derivative liabilities	4,230	4,882
Total long-term liabilities	<u>63,619</u>	<u>72,819</u>
<b>Total liabilities</b>	<u>179,269</u>	<u>144,431</u>
<b>Commitments and contingencies</b>		
<b>Shareholders' equity:</b>		
Common shares, \$0.10 par value, 100,000,000 shares authorized, 37,340,206 issued and outstanding as of December 31, 2013 and 36,874,859 as of December 31, 2012	3,734	3,687
Additional paid-in capital	542,091	537,962
Accumulated other comprehensive loss	(64,985)	(28,012)
Accumulated deficit	<u>(313,523)</u>	<u>(299,810)</u>
Total shareholders' equity	<u>167,317</u>	<u>213,827</u>
<b>Total liabilities and shareholders' equity</b>	<u><b>\$ 346,586</b></u>	<u><b>\$ 358,258</b></u>

The accompanying notes are an integral part of these consolidated financial statements.

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### TRANS ATLANTIC PETROLEUM LTD.

Consolidated Statements of Comprehensive Income (Loss)  
For the years ended December 31, 2013, 2012 and 2011  
(U.S. Dollars and shares in thousands, except per share amounts)

	2013	2012	2011
<b>Revenues:</b>			
Oil and natural gas sales	\$127,270	\$134,113	\$ 124,162
Sales of purchased natural gas	2,581	7,882	2,668
Other	976	1,913	2,075
<b>Total revenues</b>	<b>130,827</b>	<b>143,908</b>	<b>128,905</b>
<b>Costs and expenses:</b>			
Production	18,602	17,804	18,475
Exploration, abandonment and impairment	27,333	39,993	60,952
Costs of purchased natural gas	2,247	7,694	2,645
Seismic and other exploration	14,009	5,040	11,542
Revaluation of contingent consideration	(5,000)	—	6,000
General and administrative	29,020	33,947	36,305
Depreciation, depletion and amortization	41,322	28,215	39,008
Accretion of asset retirement obligations	508	710	1,142
<b>Total costs and expenses</b>	<b>128,041</b>	<b>133,403</b>	<b>176,069</b>
<b>Operating income (loss)</b>	<b>2,786</b>	<b>10,505</b>	<b>(47,164)</b>
<b>Other (expense) income:</b>			
Interest and other expense	(3,929)	(8,340)	(13,665)
Interest and other income	1,340	2,418	1,089
Loss on commodity derivative contracts	(2,698)	(5,548)	(8,426)
Foreign exchange (loss) gain	(9,663)	1,083	(11,973)
<b>Total other expense</b>	<b>(14,950)</b>	<b>(10,387)</b>	<b>(32,975)</b>
<b>(Loss) income from continuing operations before income taxes</b>	<b>(12,164)</b>	<b>118</b>	<b>(80,139)</b>
Current income tax expense	(128)	(4,674)	(2,386)
Deferred income tax (expense) benefit	(979)	(1,817)	4,951
<b>Net loss from continuing operations</b>	<b>\$ (13,271)</b>	<b>\$ (6,373)</b>	<b>\$ (77,574)</b>
<b>Loss from discontinued operations before income taxes</b>	<b>(442)</b>	<b>(5,083)</b>	<b>(39,114)</b>
Gain on disposal of discontinued operations	—	35,999	—
Income tax provision	—	(8,297)	(4,255)
<b>Net (loss) income from discontinued operations</b>	<b>(442)</b>	<b>22,619</b>	<b>(43,369)</b>
<b>Net (loss) income</b>	<b>(13,713)</b>	<b>16,246</b>	<b>(120,943)</b>
<b>Other comprehensive (loss) income:</b>			
Foreign currency translation adjustment	(36,973)	22,224	(52,069)
<b>Comprehensive (loss) income</b>	<b>\$ (50,686)</b>	<b>\$ 38,470</b>	<b>\$ (173,012)</b>
<b>Net loss per common share:</b>			
Basic net income (loss) per common share:			
Continuing operations	\$ (0.36)	\$ (0.17)	\$ (2.18)
Discontinued operations	\$ (0.01)	\$ 0.62	\$ (1.22)
Weighted average common shares outstanding	37,069	36,742	35,597
Diluted net income (loss) per common share:			
Continuing operations	\$ (0.36)	\$ (0.17)	\$ (2.18)
Discontinued operations	\$ (0.01)	\$ 0.62	\$ (1.22)
Weighted average common and common equivalent shares outstanding	37,069	36,742	35,597

The accompanying notes are an integral part of these consolidated financial statements.

**TRANS ATLANTIC PETROLEUM LTD.**  
Consolidated Statements of Equity  
For the years ended December 31, 2013, 2012 and 2011  
(U.S. Dollars and shares in thousands)

	Common Shares	Common Shares (\$)	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Shareholders' Equity
<b>Balance at December 31, 2010</b>	33,644	\$ 3,364	\$465,973	\$ 1,833	\$ (195,113)	\$ 276,057
Issuance of common shares	2,742	274	65,763	—	—	66,037
Exercise of warrants	8	1	95	—	—	96
Exercise of stock options	85	8	620	—	—	628
Issuance of restricted stock units	100	11	(11)	—	—	—
Tax withholding on restricted stock units	—	—	(210)	—	—	(210)
Share-based compensation	—	—	1,677	—	—	1,677
Foreign currency translation adjustments	—	—	—	(52,069)	—	(52,069)
Net loss	—	—	—	—	(120,943)	(120,943)
<b>Balance at December 31, 2011</b>	36,579	\$ 3,658	\$533,907	\$ (50,236)	\$ (316,056)	\$ 171,273
Issuance of common shares	—	—	—	—	—	—
Exercise of stock options	81	8	656	—	—	664
Issuance of restricted stock units	215	21	(21)	—	—	—
Tax withholding on restricted stock units	—	—	(147)	—	—	(147)
Share-based compensation	—	—	3,567	—	—	3,567
Foreign currency translation adjustment	—	—	—	22,224	—	22,224
Net income	—	—	—	—	16,246	16,246
<b>Balance at December 31, 2012</b>	36,875	\$ 3,687	\$537,962	\$ (28,012)	\$ (299,810)	\$ 213,827
Issuance of common shares	351	35	2,465	—	—	2,500
Issuance of restricted stock units	114	12	(12)	—	—	—
Tax withholding on restricted stock units	—	—	(40)	—	—	(40)
Share-based compensation	—	—	1,716	—	—	1,716
Foreign currency translation adjustment	—	—	—	(36,973)	—	(36,973)
Net loss	—	—	—	—	(13,713)	(13,713)
<b>Balance at December 31, 2013</b>	<u>37,340</u>	<u>\$ 3,734</u>	<u>\$542,091</u>	<u>\$ (64,985)</u>	<u>\$ (313,523)</u>	<u>\$ 167,317</u>

The accompanying notes are an integral part of these consolidated financial statements.

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**TRANS ATLANTIC PETROLEUM LTD.**  
Consolidated Statements of Cash Flows  
For the years ended December 31, 2013, 2012 and 2011  
(in thousands of U.S. Dollars)

	<u>2013</u>	<u>2012</u> (See Note 1)	<u>2011</u> (See Note 1)
<b>Operating activities:</b>			
Net (loss) income	\$ (13,713)	\$ 16,246	\$ (120,943)
Adjustment for net loss (income) from discontinued operations	442	(22,619)	43,369
Net loss from continuing operations	(13,271)	(6,373)	(77,574)
Adjustments to reconcile net loss to net cash provided by operating activities from continuing operations:			
Share-based compensation	1,716	2,559	1,212
Foreign currency loss	8,620	3,843	14,690
Loss on commodity derivative contracts	2,698	5,548	8,426
Cash settlement on commodity derivative contracts	(3,521)	(3,829)	(4,854)
Amortization of loan financing costs	510	1,991	1,630
Deferred income tax expense (benefit)	979	1,817	(4,951)
Inventory write down	—	1,390	—
Amortization of warrants – related party	—	—	1,972
Exploration, abandonment and impairment	27,333	39,993	60,952
Depreciation, depletion and amortization	41,322	28,215	39,008
Accretion of asset retirement obligations	508	710	1,142
Revaluation of contingent consideration	(5,000)	—	6,000
Changes in operating assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(2,353)	(6,872)	(4,985)
Prepaid expenses and other assets	(34)	(1,149)	(4,492)
Accounts payable and accrued liabilities	9,269	1,503	21,145
Net cash provided by operating activities from continuing operations	68,776	69,346	59,321
Net cash used in operating activities from discontinued operations	(1,426)	(25,769)	(10,602)
Net cash provided by operating activities	67,350	43,577	48,719
<b>Investing activities:</b>			
Acquisitions, net of cash	—	—	(747)
Additions to oil and natural gas properties	(94,266)	(70,189)	(77,027)
Additions to equipment and other properties	(10,653)	(668)	(2,648)
Restricted cash	(190)	949	5,132
Net cash used in investing activities from continuing operations	(105,109)	(69,908)	(75,290)
Net cash provided by (used in) investing activities from discontinued operations	1,016	156,149	(4,761)
Net cash (used in) provided by investing activities	(104,093)	86,241	(80,051)
<b>Financing activities:</b>			
Exercise of stock options and warrants	—	664	722
Tax withholding on restricted stock units	(40)	(147)	(210)
Loan proceeds	66,785	25,967	35,967
Loan proceeds – related party	—	11,000	—
Loan repayment	(29,785)	(78,931)	(18,024)
Loan repayment – related party	—	(84,000)	—
Loan financing costs	—	(250)	—
Net cash provided by (used in) financing activities from continuing operations	36,960	(125,697)	18,455
Net cash used in financing activities from discontinued operations	—	(5,049)	(5,068)
Net cash provided by (used in) financing activities	36,960	(130,746)	13,387
Effect of exchange rate changes on cash	(2,104)	580	(1,615)
Net decrease in cash and cash equivalents	(1,887)	(348)	(19,560)
Cash and cash equivalents, beginning of year	14,768	15,116	34,676
Cash and cash equivalents, end of year	<u>\$ 12,881</u>	<u>\$ 14,768</u>	<u>\$ 15,116</u>
<b>Supplemental disclosures:</b>			
Cash paid for interest	<u>\$ 3,091</u>	<u>\$ 6,946</u>	<u>\$ 10,106</u>
Cash paid for income taxes	<u>\$ 2,387</u>	<u>\$ 5,596</u>	<u>\$ 7,729</u>
<b>Supplemental non-cash investing and financing activities:</b>			
Note receivable – related party from sale of oilfield services business	\$ —	\$ 11,500	\$ —
Issuance of common shares for acquisitions	\$ —	\$ —	\$ 66,037
Repayment of short-term credit facility from refinancing	\$ —	\$ —	\$ 30,000
Issuance of common shares – amendment to purchase agreement	\$ 2,500	\$ —	\$ —

The accompanying notes are an integral part of these consolidated financial statements.

**T R A N S A T L A N T I C P E T R O L E U M L T D .**  
Notes to Consolidated Financial Statements

**1. General*****Nature of operations***

TransAtlantic Petroleum Ltd. (together with its subsidiaries, “we,” “us,” “our,” the “Company” or “TransAtlantic”) is an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established yet underexplored petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2013, we held interests in developed and undeveloped oil and natural gas properties in Turkey and Bulgaria. As of March 1, 2014, approximately 40% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, our chief executive officer and chairman of our board of directors.

***Basis of presentation***

Our consolidated financial statements are expressed in U.S. Dollars and have been prepared by management in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”). All amounts in these notes to the consolidated financial statements are in U.S. Dollars unless otherwise indicated. In preparing financial statements, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews estimates, including those related to fair value measurements associated with acquisitions and financial derivatives, the recoverability and impairment of long-lived assets and goodwill, contingencies and income taxes. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

***Revision of prior period financial statements***

During the three months ended March 31, 2013, we identified and corrected errors previously reported on our consolidated statements of cash flows. As a result, we increased the “Exploration, abandonment and impairment” sub-caption, which is an adjustment to reconcile net income (loss) to net cash provided by operating activities, and increased the cash used in investing activities related to “Additions to oil and natural gas properties” by \$17.4 million and \$8.3 million for the years ended December 31, 2012 and 2011, respectively, as we previously did not include the cash portion of additions to oil and natural gas properties in investing activities for dry hole expenses that were recognized in the same period as the related cash disbursed. These amounts had also been excluded from the adjustment to reconcile net income (loss) to net cash provided by operating activities.

We assessed the materiality of the errors in accordance with the U.S. Securities and Exchange Commission (the “SEC”) guidance on considering the effects of prior period misstatements based on an analysis of quantitative and qualitative factors. Based on this analysis, we determined that the errors were immaterial to each of the prior reporting periods affected and, therefore, amendments of reports previously filed with the SEC were not required. Accordingly, we have reflected the correction of these prior period errors in the periods in which they originated and revised our consolidated statement of cash flows for the years ended December 31, 2012 and 2011 in this Annual Report on Form 10-K.

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The following shows the effect of the out-of-period errors on our consolidated statements of cash flows for the years ended December 31, 2012 and 2011 (in thousands):

	<u>As Reported</u>	<u>Correction</u>	<u>As Revised</u>
<i>For the year ended December 31, 2012</i>			
<b>Operating activities:</b>			
Exploration, abandonment and impairment	\$ 22,617	\$ 17,376	\$ 39,993
Net cash provided by operating activities from continuing operations	51,970	17,376	69,346
Net cash provided by operating activities	26,201	17,376	43,577
<b>Investing activities:</b>			
Additions to oil and natural gas properties	(52,813)	(17,376)	(70,189)
Net cash used in investing activities from continuing operations	(52,532)	(17,376)	(69,908)
Net cash provided by (used in) investing activities	\$103,617	\$(17,376)	\$ 86,241
<i>For the year ended December 31, 2011</i>			
<b>Operating activities:</b>			
Exploration, abandonment and impairment	\$ 52,638	\$ 8,314	\$ 60,952
Net cash provided by operating activities from continuing operations	51,007	8,314	59,321
Net cash provided by operating activities	40,405	8,314	48,719
<b>Investing activities:</b>			
Additions to oil and natural gas properties	(68,713)	(8,314)	(77,027)
Net cash used in investing activities from continuing operations	(66,976)	(8,314)	(75,290)
Net cash used in investing activities	\$ (71,737)	\$ (8,314)	\$(80,051)

## 2. Significant accounting policies

### *Basis of preparation*

Our reporting standard for the presentation of our consolidated financial statements is U.S. GAAP. The consolidated financial statements include the accounts of the Company and all majority owned, controlled subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

### *Reverse stock split*

On March 4, 2014, the Company's shareholders approved a 1-for-10 reverse stock split, which became effective March 6, 2014. Pursuant to the reverse stock split, all shareholders of record received one common share for each ten common shares owned (subject to minor adjustments as a result of fractional shares). The reverse stock split reduced the issued and outstanding common shares from 374,026,984 to 37,402,698. U.S. GAAP requires that the reverse stock split be applied retrospectively to all periods presented. As a result, all common share transactions described herein have been adjusted to reflect the 1-for-10 reverse stock split.

### *Cash and cash equivalents*

Cash and cash equivalents include term deposits and investments with original maturities of three months or less at the date of acquisition. We consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. We determine the appropriate classification of our investments in cash and cash equivalents and marketable securities at the time of purchase and reevaluate such designation at each balance sheet date.

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### *Commodity derivative instruments*

Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 815, *Derivatives and Hedging* (“ASC 815”), requires derivative instruments to be recognized as either assets or liabilities in the balance sheet at fair value. We do not designate our derivative financial instruments as hedging instruments and, as a result, we recognize the change in a derivative contract’s fair value currently in earnings as a component of other (expense) income.

### *Fair value measurements*

We follow ASC 820, *Fair Value Measurements and Disclosures* (“ASC 820”). This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC 820 does not require any new fair value measurements, but applies to assets and liabilities that are required to be recorded at fair value under other accounting standards.

ASC 820 characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair value measurement hierarchy are as follows:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.
- Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Measured based on prices or valuation models that required inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

As required by ASC 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values takes into account the market for our financial assets and liabilities, the associated credit risk and other factors as required by ASC 820. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

### *Foreign currency remeasurement and translation*

The functional currency of our subsidiaries in Turkey, Bulgaria, Romania, and Morocco is the New Turkish Lira (“TRY”), the Bulgarian Lev, the Romanian New Leu and the Moroccan Dirham, respectively. We follow ASC 830, *Foreign Currency Matters* (“ASC 830”). ASC 830 requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. Exchange gains or losses from remeasuring transactions and monetary accounts in a currency other than the functional currency are included in earnings.

For certain subsidiaries, translation adjustments result from the process of translating the functional currency of subsidiary financial statements into the U.S. Dollar reporting currency. These translation adjustments are reported separately and accumulated in the consolidated balance sheets as a component of accumulated other comprehensive loss.

### *Oil and natural gas properties*

In accordance with the successful efforts method of accounting for oil and natural gas properties, costs of productive wells, developmental dry holes and productive leases are capitalized into appropriate groups of

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properties based on geographical and geological similarities. Acquisition costs of proved properties are amortized using the unit-of-production method based on total proved reserves, and exploration well costs and additional development costs are amortized using the unit-of-production method based on proved developed reserves. Proceeds from the sale of properties are credited to property costs, and a gain or loss is recognized when a significant portion of an amortization base is sold or abandoned.

Exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged to expense as incurred. Exploratory drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to exploration expense if and when the well is determined to be non-productive. The determination of an exploratory well's ability to produce must be made within one year from the completion of drilling activities. The acquisition costs of unproved acreage are initially capitalized and are carried at cost, net of accumulated impairment provisions, until such leases are transferred to proved properties or charged to exploration expense as impairments of unproved properties.

### ***Equipment and other property***

Equipment and other property are stated at cost, and inventory is stated at weighted average cost which does not exceed replacement cost. Depreciation is calculated using the straight-line method over the estimated useful lives (ranging from 3 to 7 years) of the respective assets. The costs of normal maintenance and repairs are charged to expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of equipment sold, or otherwise disposed of, and the related accumulated depreciation, are removed from the accounts and any gain or loss is reflected in current earnings.

### ***Impairment of long-lived assets***

We follow the provisions of ASC 360, *Property, Plant, and Equipment* ("ASC 360"). ASC 360 requires that our long-lived assets be assessed for potential impairment of their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. Proved oil and natural gas properties are evaluated by field for potential impairment. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of a field are less than its carrying value. If an impairment occurs, the carrying value of the impaired field is reduced to its estimated fair value, which is generally estimated using a discounted cash flow approach.

Unproved oil and natural gas properties do not have producing properties and are valued on acquisition by management, with the assistance of an independent expert when necessary. As reserves are proved through the successful completion of exploratory wells, the cost is transferred to proved properties. The cost of the remaining unproved basis is periodically evaluated by management to assess whether the value of a property has diminished. To do this assessment, management considers (i) estimated potential reserves and future net revenues from an independent expert, (ii) the Company's history in exploring the area, (iii) the Company's future drilling plans per its capital drilling program prepared by the Company's reservoir engineers and operations management and (iv) other factors associated with the area. Impairment is taken on the unproved property value if it is determined that the costs are not likely to be recoverable. The valuation is subjective and requires management to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual results.

### ***Goodwill***

In accordance with ASC 350, *Intangibles-Goodwill and Other* ("ASC 350"), goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise. ASC 350 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary

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to perform the two-step goodwill impairment test. We assessed the qualitative factors at December 31, 2013 and, based upon the results of the qualitative assessment, we determined that it was not necessary to perform the two-step goodwill impairment test and that our goodwill was not impaired. All of our goodwill is attributable to our Turkey operating segment.

### ***Joint interest activities***

Certain of our exploration, development and production activities are conducted jointly with other entities and, accordingly, the consolidated financial statements reflect only our proportionate interest in such activities.

### ***Asset retirement obligations***

We recognize a liability for the fair value of all legal obligations associated with the retirement of tangible, long-lived assets and capitalize an equal amount as a cost of the asset. The cost associated with the abandonment obligation is included in the computation of depreciation, depletion and amortization. The liability accretes until we settle the obligation. We use a credit-adjusted risk-free interest rate in our calculation of asset retirement obligations.

### ***Revenue recognition***

Revenue from the sale of crude oil and natural gas is recognized upon delivery to the purchaser when title passes. During the years ended December 31, 2013, 2012 and 2011, we sold \$87.2 million, \$91.8 million and \$84.3 million, respectively, of oil to Türkiye Petrol Rafinerileri A.Ş. (“TUPRAS”), a privately owned oil refinery in Turkey, which represented approximately 66.7%, 63.8% and 65.3% of our total revenues, respectively.

### ***Share-based compensation***

We follow ASC 718, *Compensation—Stock Compensation* (“ASC 718”), which requires the measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, based on estimated grant date fair values. Restricted stock units are valued using the market price of our common shares on the date of grant. We record compensation expense, net of estimated forfeitures, over the requisite service period.

### ***Income taxes***

We follow the asset and liability method prescribed by ASC 740, *Income Taxes* (“ASC 740”). Under this method of accounting for income taxes, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Under ASC 740, the effect on deferred tax assets and liabilities of a change in enacted tax rates is recognized in earnings in the period that includes the enactment date.

In connection with our acquisition Amity Oil International Pty Ltd (“Amity”) and Petrogas Petrol Gaz ve Petrokimya Ürünleri İnşaat Sanayi ve Ticaret A.Ş. (“Petrogas”) in August 2010, at December 31, 2012, we recognized a liability due to an uncertain tax position related to the transfer of Petrogas shares to Amity prior to the acquisition (see Note 11). We do not believe there will be any material changes in our unrecognized tax positions over the next twelve months. Our policy is that we recognize interest and penalties accrued on any unrecognized tax positions as a component of income tax expense.

We are a Bermuda exempted company, and under current Bermuda law, we are not subject to tax on profits, income or dividends, nor is there any capital gains tax applicable to us in Bermuda.

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### ***Comprehensive income***

ASC 220, *Comprehensive Income*, establishes standards for reporting and displaying comprehensive income and its components (revenue, expenses, gains and losses) in a full set of general-purpose financial statements.

### ***Business combinations***

We follow ASC 805, *Business Combinations* (“ASC 805”), and ASC 810-10-65, *Consolidation* (“ASC 810-10-65”). ASC 805 requires most identifiable assets, liabilities, non-controlling interests, and goodwill acquired in a business combination to be recorded at “fair value.” The statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under ASC 805, all business combinations are accounted for by applying the acquisition method.

### ***Per share information***

Basic per share amounts are calculated using the weighted average common shares outstanding during the year, excluding unvested restricted stock units. We use the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only “in the money” dilutive instruments impact the diluted calculations in computing diluted earnings per share. Diluted calculations reflect the weighted average incremental common shares that would be issued upon exercise of dilutive options assuming the proceeds would be used to repurchase shares at average market prices for the period.

## **3. New accounting pronouncements**

In February 2013, FASB issued ASU 2013-02, *New Disclosures for Items Reclassified Out of Accumulated Other Comprehensive Income* (“ASU 2013-02”). ASU 2013-02 requires reclassification adjustments for items that are reclassified out of accumulated other comprehensive income to net income to be presented in the statements where the components of net income and the components of other comprehensive income are presented or in the footnotes to the financial statements. Additionally, the amendment requires cross-referencing to other disclosures currently required for other reclassification items. The amendments were effective for interim and annual reporting periods beginning after December 15, 2012. We adopted the provisions of ASU 2013-02 as of January 1, 2013. The adoption of ASU 2013-02 did not have a material impact on our consolidated financial statements.

We have reviewed other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on our consolidated results of operations, financial position and cash flows. Based on that review, we believe that none of these pronouncements will have a significant effect on current or future earnings or operations.

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### 4. Acquisitions

#### TBNG

On June 7, 2011, TransAtlantic Worldwide, Ltd. (“TransAtlantic Worldwide”) acquired Thrace Basin Natural Gas (Türkiye) Corporation (“TBNG”) in exchange for cash consideration of \$10.5 million and the issuance of 1,850,000 of our common shares (at a deemed price of \$20.50 per common share). Of the \$10.5 million cash consideration, \$10.0 million was paid in November 2010 as an option fee and applied to the purchase price. We engaged independent valuation experts to assist in the determination of the fair value of the assets and liabilities acquired in the acquisition. The following tables summarize the consideration paid in the acquisition and the final recognized amounts of assets acquired and liabilities assumed that have been recognized at the acquisition date:

#### *Consideration:*

	(in thousands)
Cash consideration, net of purchase price adjustments	\$ 10,504
Issuance of 1,850,000 common shares	37,925
Fair value of total consideration transferred	<u>\$ 48,429</u>

#### *Acquisition-Related Costs:*

Included in general and administrative expenses on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011	<u>\$1,013</u>
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#### *Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed at Acquisition:*

Assets:	
Cash	\$ 1,845
Accounts receivable	19,997
Restricted cash	4,931
Total financial assets	26,773
Other current assets, consisting primarily of prepaid expenses	3,272
Deferred tax asset	722
Oil and natural gas properties:	
Proved properties	14,526
Unproved properties	16,131
Land and buildings	2,601
Drilling services equipment and vehicles	19,512
Total oil and natural gas properties and other equipment	52,770
Liabilities:	
Accounts payable, consisting of normal trade obligations	5,960
Other current liabilities	5,596
Asset retirement obligation	6,480
Deferred tax liability	2,523
Bank loans	14,549
Total liabilities	<u>35,108</u>
Total identifiable net assets	<u>\$48,429</u>

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As of the date of acquisition, the fair value of the accounts receivable that were acquired was \$20.0 million, consisting of a gross amount of \$23.5 million, of which \$3.5 million is not expected to be collected.

We finalized our purchase accounting in December 2011, resulting in additional accrued liabilities, increases in unproved properties and adjustments to deferred tax liabilities.

The results of operations of TBNG are included in our consolidated statement of comprehensive income (loss) beginning June 7, 2011. The revenues and loss of TBNG included in our consolidated statement of comprehensive income (loss) for the year ended December 31, 2011 were:

	<u>Revenue</u>	<u>Loss</u>
	(in thousands)	
Actual from June 7, 2011 through December 31, 2011	\$13,466	\$(4,651)

### Direct

On February 18, 2011, TransAtlantic Worldwide acquired Direct Petroleum Morocco, Inc. ("Direct Morocco") and Anschutz Morocco Corporation ("Anschutz"), and our wholly owned subsidiary TransAtlantic Petroleum Cyprus Limited acquired Direct Petroleum Bulgaria EOOD ("Direct Bulgaria") pursuant to a Purchase Agreement (the "Purchase Agreement") with Direct Petroleum, Inc. ("Direct"), for cash consideration of \$2.4 million and the issuance of 892,448 of our common shares (at a deemed price of \$31.50 per common share) to Direct, in a private placement, for total consideration of \$34.5 million. At the time of the acquisition, Direct Morocco and Anschutz owned a 50% working interest in the Ouezzane-Tissa and Asilah exploration permits in Morocco, and Direct Bulgaria owned 100% of the working interests in the A-Lovech and Aglen exploration permits in Bulgaria.

The following tables summarize the consideration paid in the acquisition of Direct Morocco, Anschutz and Direct Bulgaria and the final recognized amounts of assets acquired and liabilities assumed which have been recognized at the acquisition date:

#### Consideration:

	(in thousands)
Cash consideration, net of purchase price adjustments	\$ 2,408
Issuance of 892,448 common shares	28,112
Contingent consideration liabilities	4,000
Fair value of total consideration transferred	<u>\$ 34,520</u>

The Purchase Agreement provided that if certain post-closing milestones were achieved, we would issue additional consideration to Direct equal to: (i) \$10.0 million worth of our common shares if the Deventci-R2 well in Bulgaria was a commercial success and (ii) \$10.0 million worth of our common shares if Direct Bulgaria received a production concession for a specified area in Bulgaria. The fair value of these contingent consideration liabilities represents our best estimate of the amounts to be paid as additional consideration. Subsequent changes in the fair value of the contingent consideration liabilities are reflected in our consolidated statements of comprehensive income (loss). The fair value of these contingent consideration liabilities was \$2.5 million at December 31, 2013 and \$10.0 million at December 31, 2012. The change in the contingent consideration liabilities since the acquisition date is included under the caption "Revaluation of contingent consideration" on our consolidated statements of comprehensive income (loss) for the years ended December 31, 2013, 2012, and 2011. In July 2013, we amended the Purchase Agreement, which resulted in changes in the contingent consideration liability (see Note 15).

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### *Acquisition-Related Costs:*

	<u>(in thousands)</u>
Included in general and administrative expenses on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011	<u>\$ 117</u>

### *Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed at Acquisition:*

	<u>(in thousands)</u>
<b>Assets:</b>	
Cash	\$ 320
Accounts receivable	<u>57</u>
Total financial assets	377
Other current assets, consisting primarily of prepaid expenses	146
Oil and natural gas properties:	
Proved properties	1,200
Unproved properties	32,840
Other equipment	<u>79</u>
Total oil and natural gas properties and other equipment	34,119
<b>Liabilities:</b>	
Accounts payable, consisting of normal trade obligations	<u>122</u>
Total identifiable net assets	<u>\$ 34,520</u>

The results of operations of Direct Morocco, Anschutz and Direct Bulgaria are included in our consolidated statement of comprehensive income (loss) beginning February 18, 2011, the closing date of the acquisition.

The amounts of revenue and loss of Direct Morocco, Anschutz and Direct Bulgaria included in our consolidated statement of comprehensive income (loss) for the year ended December 31, 2011 are shown below:

	<u>Revenue</u>	<u>Loss</u>
	<u>(in thousands)</u>	
Continuing operations	\$ 483	\$(30,749) <sup>(1)</sup>
Discontinued operations	<u>—</u>	<u>(7,021)</u>
Total from February 18, 2011 through December 31, 2011	<u>\$ 483</u>	<u>\$(37,770)</u>

(1) See Note 6, Property and equipment, for a discussion of the impairment of our properties in Bulgaria.

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### Pro forma results of operations

The following table presents the unaudited pro forma results of operations for the year ended December 31, 2011 as though the acquisitions of Direct Morocco, Anschutz, Direct Bulgaria and TBNG had occurred as of January 1, 2011 (in thousands, except per share amounts):

	<u>2011</u>
Total revenues	\$ 139,999
Loss from continuing operations before income taxes	(82,856)
Loss from continuing operations	(80,834)
Loss from discontinued operations	(45,071)
Net loss	(125,905)
Net loss per common share from continuing operations	
Basic	\$ (2.21)
Diluted	\$ (2.21)
Net loss per common share from discontinued operations	
Basic	\$ (1.23)
Diluted	\$ (1.23)

### 5. Goodwill

Goodwill represents the excess of the purchase price of a business over the estimated fair value of the assets acquired and liabilities assumed. We have goodwill on acquisitions where we anticipated access to potential exploration and producing opportunities. All of our goodwill is attributable to our Turkey operating segment. Goodwill was as follows at December 31, 2013 and 2012:

	<u>2013</u>	<u>2012</u>
	(in thousands)	
Goodwill at January 1,	\$ 9,021	\$8,514
Foreign exchange change effect	(1,486)	507
Goodwill at December 31,	<u>\$ 7,535</u>	<u>\$9,021</u>

### 6. Property and equipment

#### Oil and natural gas properties

The following table sets forth the capitalized costs under the successful efforts method for oil and natural gas properties:

	<u>December 31, 2013</u>	<u>December 31, 2012</u>
	(in thousands)	
Oil and natural gas properties, proved:		
Turkey	\$ 260,232	\$ 229,462
Bulgaria	625	2,036
Total oil and natural gas properties, proved	260,857	231,498
Oil and natural gas properties, unproved:		
Turkey	51,273	68,938
Bulgaria	3,119	—
Total oil and natural gas properties, unproved	54,392	68,938
Gross oil and natural gas properties	315,249	300,436
Accumulated depletion	(96,958)	(74,099)
Net oil and natural gas properties	<u>\$ 218,291</u>	<u>\$ 226,337</u>

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At December 31, 2013 and 2012, we excluded \$1.5 million and \$1.8 million of costs, respectively, from the depletion calculation for development wells in progress and for costs on fields currently not in production.

At December 31, 2013, the capitalized costs of our oil and natural gas properties included \$35.5 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and \$126.9 million relating to well costs, and additional development costs, which are being amortized by the unit-of-production method using proved developed reserves.

At December 31, 2012, the capitalized costs of our oil and natural gas properties included \$49.5 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and \$105.3 million relating to well costs, and additional development costs, which are being amortized by the unit-of-production method using proved developed reserves.

### *Dry hole costs*

During the years ended December 31, 2013, 2012 and 2011, we recorded \$16.0 million, \$24.7 million, and \$26.8 million of exploratory dry hole costs, respectively. Of the \$16.0 million of dry hole costs incurred during the year ended December 31, 2013, approximately \$10.0 million was related to cash spent during 2013.

### *Impairment and abandonment*

Unproved oil and natural gas properties that are individually significant are periodically assessed for impairment, and a loss is recognized at the time of impairment. Capitalized costs related to proved oil and natural gas properties, including wells and related equipment and facilities, are evaluated for impairment based on our analysis of undiscounted future net cash flows. If undiscounted future net cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income equal to the difference between the carrying value and the estimated fair value of the properties. We categorize the measurement of fair value of these assets as Level 3 inputs. Estimated fair values are determined using discounted cash flow models. The discounted cash flow models include management's estimates of future oil and natural gas production, operating and development costs, and discount rates.

During the year ended December 31, 2013, we recorded \$11.3 million in impairment and abandonment charges on our proved and unproved properties, primarily related to our Senova and Malkara licenses.

During the year ended December 31, 2012, we recorded \$6.7 million in impairment charges on our proved properties, of which \$2.7 million was due to downward revisions in natural gas reserves in our Alpullu field. We recorded a \$8.4 million impairment on our unproved oil and natural gas properties during the year ended December 31, 2012. Of this amount, \$5.2 million was attributable to exploration license acquisition costs for the Banarli license.

During the year ended December 31, 2011, we recorded a \$30.2 million impairment on our unproved oil and natural gas properties. Of this amount, \$25.9 million was attributable to our Bulgarian properties. We impaired our Bulgarian properties following the enactment by the Bulgarian Parliament of legislation which banned fracture stimulation in the Republic of Bulgaria. We also recorded \$14.6 million in impairment charges on two of our proved properties in Turkey, primarily due to downward revisions in natural gas reserves in the Alpullu and Edirne fields.

### *Capitalized cost greater than one year*

As of December 31, 2013, we had \$2.6 million of exploratory well costs capitalized for the Kazanci-5 well, which we spud in September 2012. We recently finished a long-term pressure build up on the current completion and have identified potential pay up-hole. We are evaluating, with our partners, whether to test another unconventional zone or to move up to the conventional pay and establish production.

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### *Equipment and other property*

The historical cost of equipment and other property, presented on a gross basis with accumulated depreciation, is summarized as follows:

	December 31,	
	2013	2012
	(in thousands)	
Other equipment	\$ 2,678	\$ 2,013
Inventory	24,318	20,517
Gas gathering system and facilities	4,485	5,369
Vehicles	321	131
Leasehold improvements, office equipment and software	8,114	7,717
Gross equipment and other property	39,916	35,747
Accumulated depreciation	(7,235)	(5,932)
Net equipment and other property	<u>\$32,681</u>	<u>\$29,815</u>

We classify our materials and supply inventory, including steel tubing and casing, as a long-term asset because such materials will ultimately be classified as a long-term asset when the material is used in the drilling of a well.

At December 31, 2013, we excluded \$24.3 million of inventory and \$0.7 million of software from depreciation, as the inventory and software had not been placed into service. At December 31, 2012, we excluded \$20.5 million of inventory from depreciation as the inventory had not been placed into service.

### **7. Commodity derivative instruments**

We use collar derivative contracts to economically hedge against the variability in cash flows associated with the forecasted sale of a portion of our future oil production. We have not designated the derivative contracts as hedges for accounting purposes, and accordingly, we record the derivative contracts at fair value and recognize changes in fair value in earnings as they occur.

To the extent that a legal right of offset exists, we net the value of our derivative contracts with the same counterparty in our consolidated balance sheets. All of our oil derivative contracts are settled based upon Brent crude oil pricing. We recognize gains and losses related to these contracts on a fair value basis in our consolidated statements of comprehensive income (loss) under the caption “Loss on commodity derivative contracts.” Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows under the caption “Cash settlement on commodity derivative contracts.” We are required under our amended and restated credit facility (the “Amended and Restated Credit Facility”) with BNP Paribas (Suisse) SA (“BNP Paribas”) and Standard Bank Plc (“Standard Bank”), to hedge between 30% and 75% of our anticipated production volumes in the Selmo and Arpatepe oil fields in Turkey.

During the years ended December 31, 2013, 2012 and 2011, we recorded net losses on commodity derivative contracts of \$2.7 million, \$5.5 million, and \$8.4 million respectively.

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At December 31, 2013, we had outstanding commodity derivative contracts with respect to our future crude oil production as set forth in the tables below:

### Fair Value of Derivative Instruments as of December 31, 2013

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Collar	January 1, 2014—December 31, 2014	622	\$ 80.83	\$ 118.07	\$ (387)
					<u>\$ (387)</u>
Type	Period	Quantity (Bbl/day)	Collars Weighted		Additional Call
			Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	
Type	Period	Quantity (Bbl/day)	Price (per Bbl)	Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Three-way collar contract	January 1, 2014—December 31, 2014	726	\$ 85.00	\$ 97.13	\$ (3,350)
Three-way collar contract	January 1, 2015—December 31, 2015	1,016	\$ 85.00	\$ 91.88	(4,230)
					<u>\$ (7,580)</u>

At December 31, 2012, we had outstanding commodity derivative contracts with respect to our future crude oil production as set forth in the tables below:

### Fair Value of Derivative Instruments as of December 31, 2012

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Collar	January 1, 2013—December 31, 2013	775	\$ 82.26	\$ 121.36	\$ (253)
Collar	January 1, 2014—December 31, 2014	622	\$ 80.83	\$ 118.07	(292)
					<u>\$ (545)</u>
Type	Period	Quantity (Bbl/day)	Collars Weighted		Additional Call
			Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	
Type	Period	Quantity (Bbl/day)	Price (per Bbl)	Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Three-way collar contract	January 1, 2013—December 31, 2013	831	\$ 85.00	\$ 97.13	\$ (3,655)
Three-way collar contract	January 1, 2014—December 31, 2014	726	\$ 85.00	\$ 97.13	(2,150)
Three-way collar contract	January 1, 2015—December 31, 2015	1,016	\$ 85.00	\$ 91.88	(2,440)
					<u>\$ (8,245)</u>

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### 8. Asset retirement obligations

As part of our development of oil and natural gas properties, we incur asset retirement obligations (“ARO”). Our ARO results from our responsibility to abandon and reclaim our net share of all working interest properties and facilities. At December 31, 2013, the net present value of our total ARO was estimated to be \$10.9 million, with the undiscounted value being \$18.5 million. Total ARO at December 31, 2013 shown in the table below consists of amounts for future plugging and abandonment liabilities on our wellbores and facilities based on third-party estimates of such costs, adjusted for inflation at a rate of approximately 6.2% per annum for Turkey and 2.5% for Bulgaria. These values are discounted to present value using our credit-adjusted risk-free rate of 5.75% per annum for the years ended December 31, 2013 and 2012. The following table summarizes the changes in our ARO for the years ended December 31, 2013 and 2012:

	2013	2012
	(in thousands)	
Asset retirement obligation January 1,	\$11,958	\$13,534
Change in estimates <sup>(1)</sup>	(7)	(3,868)
Liabilities settled	(296)	(110)
Foreign exchange change effect	(2,258)	793
Additions	991	899
Accretion expense	508	710
Asset retirement obligation at December 31,	10,896	11,958
Less: current portion	610	818
Long-term portion	<u>\$10,286</u>	<u>\$11,140</u>

(1) For 2013 and 2012, we used cost estimates provided by third-party engineers.

Our ARO is measured using primarily Level 3 inputs. The significant unobservable inputs to this fair value measurement include estimates of plugging costs, remediation costs, inflation rate and well life. The inputs are calculated based on historical data as well as current estimated costs.

### 9. Loans payable

As of the dates indicated, our third-party debt consisted of the following:

	December 31,	December 31,
	2013	2012
	(in thousands)	
<b>Floating Rate Debt</b>		
Amended and Restated Credit Facility	\$ 49,766	\$ 32,766
TBNG credit facility (short-term)	20,000	—
Loans payable	69,766	32,766
Less: current portion	43,284	—
Long-term portion	<u>\$ 26,482</u>	<u>\$ 32,766</u>

#### *Amended and Restated Credit Facility*

On May 18, 2011, DMLP, Ltd. (“DMLP”), TransAtlantic Exploration Mediterranean International Pty Ltd (“TEMI”), Talon Exploration, Ltd. (“Talon Exploration”), TransAtlantic Turkey, Ltd. (“TransAtlantic Turkey”) and Petrogas (collectively, and together with Amity, the “Borrowers”) entered into the Amended and Restated Credit Facility. Each of the Borrowers is our wholly owned subsidiary. In July 2011, Amity executed a joinder agreement and became a borrower under the Amended and Restated Credit Facility. The Amended and Restated Credit Facility is guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide.

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The Amended and Restated Credit Facility matures on the earlier of (i) May 18, 2016 or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual report of Standard Bank and the Borrowers determines that the aggregate amount of hydrocarbons to be produced from the borrowing base assets in Turkey are less than 25% of the amount of hydrocarbons to be produced from the borrowing base assets shown in the initial report prepared by Standard Bank and the Borrowers. The Amended and Restated Credit Facility bears various letter of credit sub-limits, including among other things, sub-limits of up to (i) \$10.0 million, (ii) the aggregate available unused and uncanceled portion of the lenders' commitments or (iii) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender's individual commitment.

Loans under the Amended and Restated Credit Facility accrue interest at a rate of three-month LIBOR plus 5.50% per annum (5.74% at December 31, 2013). The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.20% per annum of the unused and uncanceled portion of the aggregate commitments that is less than or equal to the maximum available amount under the Amended and Restated Credit Facility, and (b) 1.10% per annum of the unused and uncanceled portion of the aggregate commitments that exceed the maximum available amount under the Amended and Restated Credit Facility and is not available to be borrowed, (ii) on the date of issuance of any letter of credit, a fronting fee in an amount equal to 0.25% of the original maximum amount to be drawn under such letter of credit and (iii) a per annum letter of credit fee for each letter of credit issued equal to the face amount of such letter of credit multiplied by (a) 1.0% for any letter of credit that is cash collateralized or backed by a standby letter of credit issued by a financial institution acceptable to Standard Bank or (b) 5.50% for all other letters of credit.

In November 2012, we entered into an amendment to the Amended and Restated Credit Facility. The amendment, among other things, reduced the commitment fee rates and extended the first commitment reduction date from September 30, 2012 to December 31, 2013. In addition, the amendment provided for a scheduled quarterly reduction of the commitment amount beginning on December 31, 2013, when the commitment amount will be reduced to \$67.5 million, and ending on March 31, 2016, when the commitment amount will reach zero.

Availability under the Amended and Restated Credit Facility is subject to a borrowing base. The borrowing base was re-determined semi-annually on April 1st and October 1st of each year prior to September 30, 2012, and is now re-determined quarterly on January 1st, April 1st, July 1st and October 1st of each year. Following our borrowing base redetermination on October 1, 2012, the borrowing base at December 31, 2012 was \$59.7 million. Following our borrowing base redetermination on October 1, 2013, the borrowing base is currently \$50.6 million. In June 2012, we used a portion of the net proceeds from the sale of our oilfield services business to pay down approximately \$45.2 million in outstanding indebtedness under the Amended and Restated Credit Facility.

At December 31, 2013, we had borrowed \$49.8 million under the Amended and Restated Credit Facility.

We are currently in the process of refinancing the Amended and Restated Credit Facility. In January 2014, we executed a mandate letter with two financial institutions. We expect to complete the refinancing in the second quarter of 2014. If we are unable to complete the refinancing of our Amended and Restated Credit Facility, we would curtail certain discretionary expenditures, and believe our resulting cash flow from operations and existing cash on hand are sufficient to conduct our operations through 2014 and meet our contractual obligations.

At December 31, 2013, we were not in compliance with Section 8.17(a) of our Amended and Restated Credit Facility, which requires the Borrowers to maintain a current ratio of not less than 1.10:1.0. The lenders have granted the Borrowers a waiver on the current ratio requirement through March 31, 2015.

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### ***TBNG credit facility***

On June 18, 2013, TBNG entered into a 78.8 million TRY (approximately \$36.9 million at December 31, 2013) unsecured line of credit with a Turkish bank, of which 60 million TRY is available in cash for TBNG and 18.8 million TRY is available in the form of non-cash bank guarantees and letters of credit for TBNG and several other of our wholly owned subsidiaries operating in Turkey. The interest rate is established at the time of each borrowing. We have made two borrowings under this credit facility, on October 9, 2013 and November 5, 2013, each of which has a one-year term at a fixed interest rate of 4.6% per annum. At maturity, we expect to renew the borrowings for one additional year at then current market interest rates. As of December 31, 2013, we had borrowed \$20.0 million under this credit facility.

### **10. Shareholders' equity**

#### ***July 2013 share issuance***

In July 2013, we issued 351,074 common shares at a deemed price of \$7.12 per common share to Direct (see Note 15).

#### ***June 2011 share issuance***

In June 2011, we issued 1,850,000 common shares at a deemed price of \$20.50 per common share in a private placement to an accredited investor in connection with the acquisition of TBNG.

#### ***February 2011 share issuance***

In February 2011, we issued 892,448 common shares at a deemed price of \$31.50 per common share in a private placement to an accredited investor in connection with the acquisition of Direct Morocco, Anschutz and Direct Bulgaria.

#### ***Restricted stock units***

Under our 2009 Long-Term Incentive Plan (the "Incentive Plan"), we award restricted stock units ("RSUs") and other share-based compensation to certain of our directors, officers, employees and consultants. Each RSU is equal in value to one of our common shares on the grant date. Upon vesting, an award recipient is entitled to a number of common shares equal to the number of vested RSUs. The RSU awards can only be settled in common shares. As a result, RSUs are classified as equity. At the grant date, we make an estimate of the forfeitures expected to occur during the vesting period and record compensation cost, net of the estimated forfeitures, over the requisite service period. The current forfeiture rate is estimated to be 10%.

Under the Incentive Plan, RSUs vest over specified periods of time ranging from immediately to four years. RSUs are deemed full value awards and their value is equal to the market price of our common shares on the grant date. ASC 718 requires that the Incentive Plan be approved in order to establish a grant date. Under ASC 718, the approval date for the Incentive Plan was February 9, 2009, the date our board of directors approved the Incentive Plan.

In connection with the sale of our oilfield services business, we accelerated the vesting of RSUs for employees of this business, and we recognized \$1.0 million in share-based compensation expense during the three months ended June 30, 2012. Total share-based compensation of approximately \$1.7 million and \$3.6 million with respect to awards of RSUs was recorded for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013, we had approximately \$1.3 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 1.4 years.

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The following table sets forth RSU activity for the year ended December 31, 2013:

	Number of RSUs (in thousands)	Weighted Average Grant Date Fair Value Per RSU
Unvested RSUs outstanding at December 31, 2012	315	\$ 12.46
Granted	172	7.10
Forfeited	(62)	10.20
Vested	(129)	14.53
Unvested RSUs outstanding at December 31, 2013	<u>296</u>	<u>\$ 8.91</u>

### Stock option plan

Our Amended and Restated Stock Option Plan (2006) (the “Option Plan”) terminated on June 16, 2009. All outstanding awards issued under the Option Plan remained in full force and effect. As of December 31, 2013, there were no options outstanding under the Option Plan. All options previously outstanding under the Option Plan had a five-year term.

The fair value of stock options is determined using the Black-Scholes Model and is recognized over the service period of the stock option. All stock options are fully vested; therefore, no share-based compensation expense for stock option awards was recorded for the years ended December 31, 2013, 2012 and 2011. We did not grant any stock options during the years ended December 31, 2013, 2012 and 2011.

Details of stock option activity for the years ended December 31, 2013, 2012 and 2011 are presented below.

	2013		2012		2011	
	Number of Options (in thousands)	Weighted Average Exercise Price Per Share	Number of Options (in thousands)	Weighted Average Exercise Price Per Share	Number of Options (in thousands)	Weighted Average Exercise Price Per Share
Outstanding at January 1,	16	\$ 12.30	114	\$ 9.07	211	\$ 8.60
Granted	—	—	—	—	—	—
Expired	(16)	12.30	(17)	10.00	(13)	12.96
Exercised	—	—	(81)	8.24	(84)	7.39
Outstanding at December 31,	<u>—</u>	<u>\$ —</u>	<u>16</u>	<u>\$ 12.30</u>	<u>114</u>	<u>\$ 9.07</u>
Exercisable at December 31,	<u>—</u>	<u>\$ —</u>	<u>16</u>	<u>\$ 12.30</u>	<u>114</u>	<u>\$ 9.07</u>

### Earnings per share

We account for earnings per share in accordance with ASC Subtopic 260-10, *Earnings Per Share* (“ASC 260-10”). ASC 260-10 requires companies to present two calculations of earnings per share: basic and diluted. Basic earnings per common share for the years ended December 31, 2013, 2012 and 2011 equals net income divided by the weighted average shares outstanding during the periods. Weighted average shares outstanding are equal to the weighted average of all shares outstanding for the period, excluding RSUs. Diluted earnings per common share for the years ended December 31, 2013, 2012 and 2011 are computed in the same manner as basic earnings per common share after assuming the issuance of common shares for all potentially dilutive common share equivalents, which includes stock options, RSUs and warrants, whether exercisable or not. The computation of diluted earnings per common share excluded 758,586, 959,438 and 2,075,213 antidilutive common share equivalents from the years ended December 31, 2013, 2012 and 2011, respectively.

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The following table presents the basic and diluted earnings per common share computations:

	<u>2013</u>	<u>2012</u>	<u>2011</u>
<u>(in thousands, except per share amounts)</u>			
Net loss from continuing operations	\$(13,271)	\$ (6,373)	\$(77,574)
Net (loss) income from discontinued operations	\$ (442)	\$22,619	\$(43,369)
Basic net (loss) income per common share:			
Shares:			
Weighted average common shares outstanding	<u>37,069</u>	<u>36,742</u>	<u>35,597</u>
Basic net (loss) income per common share:			
Continuing operations	<u>\$ (0.36)</u>	<u>\$ (0.17)</u>	<u>\$ (2.18)</u>
Discontinued operations	<u>\$ (0.01)</u>	<u>\$ 0.62</u>	<u>\$ (1.22)</u>
Diluted net (loss) income per common share:			
Shares:			
Weighted average common shares and common equivalent shares outstanding	<u>37,069</u>	<u>36,742</u>	<u>35,597</u>
Diluted net (loss) income per common share:			
Continuing operations	<u>\$ (0.36)</u>	<u>\$ (0.17)</u>	<u>\$ (2.18)</u>
Discontinued operations	<u>\$ (0.01)</u>	<u>\$ 0.62</u>	<u>\$ (1.22)</u>

Additionally, we had a contingent liability at December 31, 2013 of approximately \$2.5 million that is payable in our common shares. At the December 31, 2013 closing price of our common shares, this liability represented 294,117 common shares that could be potentially dilutive to future earnings per share calculations.

## 11. Income taxes

The income tax provision differs from the amount that would be obtained by applying the Bermuda statutory income tax rate of 0% for 2013, 2012 and 2011 to loss for the year as follows:

	<u>2013</u>	<u>2012</u> (in thousands)	<u>2011</u>
Statutory tax rate	0.00%	0.00%	0.00%
Income (loss) from continuing operations before income taxes	\$(12,164)	\$ 118	\$(80,139)
Increase (decrease) resulting from:			
Foreign tax rate differentials	(1,443)	8,607	(11,173)
Change in valuation allowance	982	(2,026)	6,871
Expiration of non-capital tax loss carryovers	1,367	1,601	1,198
Other	201	(1,691)	539
Total	<u>\$ 1,107</u>	<u>\$ 6,491</u>	<u>\$ (2,565)</u>

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The components of the net deferred income tax liability at December 31, 2013 and 2012 were as follows:

	2013	2012
	(in thousands)	
Deferred tax assets		
Unrealized derivative losses	\$ 1,594	\$ 1,758
Timing of accruals	1,043	1,251
Non-capital loss carryovers	25,868	28,455
Valuation Allowance	(28,404)	(29,059)
Total deferred tax assets	<u>101</u>	<u>2,405</u>
Deferred tax liabilities		
Property and equipment	\$(13,093)	\$(16,993)
Total deferred tax liabilities	<u>(13,093)</u>	<u>(16,993)</u>
Net deferred tax liabilities	<u>\$(12,992)</u>	<u>\$(14,588)</u>
Components of net deferred tax liabilities		
Current assets	\$ 2,239	\$ 1,895
Non-current assets	903	—
Non-current liabilities	(16,134)	(16,483)
Net deferred tax liabilities	<u>\$(12,992)</u>	<u>\$(14,588)</u>

We have accumulated losses or resource-related deductions available for income tax purposes in Turkey, Romania, Bulgaria and the United States. As of December 31, 2013, we had non-capital tax losses in Turkey of approximately 134.0 million TRY (approximately \$62.8 million), which will begin expiring in 2014; non-capital tax losses in Romania of approximately 24.9 million Romanian New Leu (approximately \$7.7 million), which will begin expiring in 2014; non-capital losses in Bulgaria of approximately 5.8 million Bulgarian Lev (approximately \$4.1 million), which will begin expiring in 2014; and non-capital tax losses in the United States of approximately \$26.1 million, which will begin expiring in 2018.

Effective October 1, 2009, we continued to the jurisdiction of Bermuda. We have determined that no taxes were payable upon the continuance. However, our tax filing positions are still subject to review by taxation authorities who may successfully challenge our interpretation of the applicable tax legislation and regulations, with the result that additional taxes could be payable by us.

We file income tax returns in the United States, Turkey, Romania, Bulgaria, Morocco and Cyprus, with Turkey being the only jurisdiction with significant amounts of taxes due. Income tax returns filed in Turkey for years before 2008 are no longer subject to examination. The Turkish Ministry of Finance is currently conducting tax audits on two of our Turkish subsidiaries, Amity and TBNG, for the years ended December 31, 2010 and 2012, respectively. The Turkish Ministry of Finance recently began an audit of our Turkish subsidiary, TEMI, for the year ended December 31, 2010.

In connection with our acquisition of Amity and Petrogas in August 2010, at December 31, 2012, we recognized a liability due to an uncertain tax position related to the transfer of Petrogas shares to Amity prior to the acquisition. Pursuant to the Amity share purchase agreement, we are indemnified from any tax liability arising in Turkey or Australia as a result of the transfer of the Petrogas shares for a period of up to six years from the sale date at an amount up to 50% of the purchase price of \$96.3 million and, therefore, have recorded a corresponding receivable in other long-term assets.

As of December 31, 2013 the liability and receivable consisted of taxes of \$3.3 million, penalties of \$0.7 million and interest of \$1.8 million. During the years ended December 31, 2013 and 2012, the Company recorded interest of \$0.5 million and \$1.3 million, respectively.

As of December 31, 2013, there were no material uncertain tax positions for which the total amounts of unrecognized tax benefits will significantly increase or decrease within the next 12 months.

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### 12. Segment information

In accordance with ASC 280, *Segment Reporting* ("ASC 280"), we have two reportable geographic segments: Turkey and Bulgaria. Summarized financial information from continuing operations concerning our geographic segments is shown in the following tables:

	Corporate	Turkey (in thousands)	Bulgaria	Total
<i>For the year ended December 31, 2013</i>				
Total revenues	\$ —	\$130,701	\$ 126	\$130,827
Production	5	18,384	213	18,602
Exploration, abandonment and impairment	—	27,116	217	27,333
Cost of purchased natural gas	—	2,247	—	2,247
Seismic and other exploration	100	13,909	—	14,009
Revaluation of contingent consideration	—	—	(5,000)	(5,000)
General and administrative	12,685	16,068	267	29,020
Depreciation, depletion and amortization	69	41,196	57	41,322
Accretion of asset retirement obligations	—	475	33	508
Total costs and expenses	12,859	119,395	(4,213)	128,041
Operating (loss) income	(12,859)	11,306	4,339	2,786
Interest and other expense	—	(3,929)	—	(3,929)
Interest and other income	284	1,056	—	1,340
Loss on commodity derivative contracts	—	(2,698)	—	(2,698)
Foreign exchange (loss) gain	(9)	(9,664)	10	(9,663)
Income (loss) from continuing operations before income taxes	(12,584)	(3,929)	4,349	(12,164)
Income tax provision	—	(1,107)	—	(1,107)
Net (loss) income from continuing operations	\$(12,584)	\$ (5,036)	\$ 4,349	\$(13,271)
Total assets as of December 31, 2013	\$ 14,070	\$321,749	\$10,231	\$346,050 <sup>(1)</sup>
Goodwill as of December 31, 2013	\$ —	\$ 7,535	\$ —	\$ 7,535
Capital expenditures	\$ 1,003	\$ 96,206	\$ 2,742	\$ 99,951
<i>For the year ended December 31, 2012</i>				
Total revenues	\$ —	\$143,650	\$ 258	\$143,908
Production	169	17,328	307	17,804
Exploration, abandonment and impairment	285	39,708	—	39,993
Cost of purchased natural gas	—	7,694	—	7,694
Seismic and other exploration	304	4,726	10	5,040
General and administrative	10,982	20,603	2,362	33,947
Depreciation, depletion and amortization	30	28,092	93	28,215
Accretion of asset retirement obligations	—	679	31	710
Total costs and expenses	11,770	118,830	2,803	133,403
Operating (loss) income	(11,770)	24,820	(2,545)	10,505
Interest and other expense	(1,890)	(6,450)	—	(8,340)
Interest and other income	308	2,110	—	2,418
Loss on commodity derivative contracts	—	(5,548)	—	(5,548)
Foreign exchange gain (loss)	79	1,054	(50)	1,083
Income (loss) from continuing operations before income taxes	(13,273)	15,986	(2,595)	118
Income tax provision	—	(6,491)	—	(6,491)
Net income (loss) from continuing operations	\$(13,273)	\$ 9,495	\$ (2,595)	\$(6,373)
Total assets as of December 31, 2012	\$ 14,930	\$339,752	\$ 1,957	\$356,639 <sup>(1)</sup>
Goodwill as of December 31, 2012	\$ —	\$ 9,021	\$ —	\$ 9,021
Capital expenditures	\$ —	\$ 80,957	\$ 867	\$ 81,824

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	Corporate	Turkey	Bulgaria	Total
	(in thousands)			
For the year ended December 31, 2011				
Total revenues	\$ 66	\$128,356	\$ 483	\$128,905
Production	359	17,484	632	18,475
Exploration, abandonment and impairment	2	37,008	23,942	60,952
Cost of purchased natural gas	—	2,645	—	2,645
Seismic and other exploration	1,801	9,657	84	11,542
Revaluation of contingent consideration	—	—	6,000	6,000
General and administrative	14,714	21,585	6	36,305
Depreciation, depletion and amortization	127	38,389	492	39,008
Accretion of asset retirement obligations	—	1,131	11	1,142
Total costs and expenses	17,003	127,899	31,167	176,069
Operating (loss) income	(16,937)	457	(30,684)	(47,164)
Interest and other (expense) income	(6,784)	(6,878)	(3)	(13,665)
Interest and other income	27	914	148	1,089
Loss on commodity derivative contracts	—	(8,426)	—	(8,426)
Foreign exchange loss	(23)	(11,740)	(210)	(11,973)
Loss from continuing operations before income taxes	(23,717)	(25,673)	(30,749)	(80,139)
Income tax benefit	—	2,565	—	2,565
Net loss from continuing operations	\$(23,717)	\$ (23,108)	\$(30,749)	\$(77,574)
Total assets as of December 31, 2011	\$ 3,716	\$313,754	\$ 4,164	\$321,634 <sup>(1)</sup>
Goodwill as of December 31, 2011	\$ —	\$ 8,514	\$ —	\$ 8,514
Capital expenditures	\$ —	\$117,071	\$ 35,369	\$152,440

(1) Excludes assets from our discontinued Moroccan operations and oilfield services business of \$0.5 million, \$1.6 million, and \$127.2 million at December 31, 2013, 2012 and 2011, respectively.

### 13. Financial instruments

#### *Interest rate risk*

We are exposed to interest rate risk as a result of our variable rate short-term cash holdings and borrowings under the Amended and Restated Credit Facility.

#### *Foreign currency risk*

We have underlying foreign currency exchange rate exposure. Our currency exposures relate to transactions denominated in the Bulgarian Lev, European Union Euro, and TRY. We are also subject to foreign currency exposures resulting from translating the functional currency of our subsidiary financial statements into the U.S. Dollar reporting currency. We have not used foreign currency forward contracts to manage exchange rate fluctuations. At December 31, 2013, we had 22.8 million TRY (approximately \$10.7 million) in cash and cash equivalents, which exposes us to exchange rate risk based on fluctuations in the value of the TRY.

#### *Commodity price risk*

We are exposed to fluctuations in commodity prices for oil and natural gas. Commodity prices are affected by many factors, including but not limited to, supply and demand. At December 31, 2013 and 2012, we were a party to commodity derivative contracts.

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### Concentration of credit risk

The majority of our receivables are within the oil and natural gas industry, primarily from our industry partners and from government agencies. Included in receivables are amounts due from Türkiye Petrolleri Anonim Ortaklığı (“TPAO”), the national oil company of Turkey, Zorlu Dogal Gaz İthalat İhracat ve Toptan Ticaret A.Ş. (“Zorlu”), a privately owned natural gas distributor in Turkey, and TUPRAS, which purchase the majority of our oil and natural gas production. The receivables are not collateralized. To date, we have experienced minimal bad debts and have no allowance for doubtful accounts. The majority of our cash and cash equivalents are held by three financial institutions in the United States and Turkey.

### Fair value measurements

Cash and cash equivalents, receivables, accounts payable, accrued liabilities, and the TBNG credit facility were each estimated to have a fair value approximating the carrying amount at December 31, 2013 and 2012 due to the short maturity of those instruments. Indebtedness under the Amended and Restated Credit Facility was estimated to have a fair value approximating the carrying amount at December 31, 2013 and 2012 since the interest rate is generally market sensitive.

The financial assets and liabilities measured on a recurring basis at December 31, 2013 and 2012 consisted of our commodity derivative contracts. Fair values for options are based on counterparty market prices. The counterparties use market standard valuation methodologies incorporating market inputs for volatility and risk free interest rates in arriving at a fair value for each option contract. Prices are verified by us using analytical tools. There are no performance obligations related to the call options purchased to hedge our oil production.

We utilize independent third-party pricing services to determine the fair values of derivative contracts. The independent third party determines fair values using models based on a range of observable market inputs, including pricing models, quoted market prices of publicly traded securities with similar duration and yield, time value, yield curve, prepayment spreads, default rates and discounted cash flow and the values for these contracts are disclosed in Level 2 of the fair value hierarchy. Generally, we obtain a single price or quote per instrument from independent third parties to assist in establishing the fair value of these contracts. We review prices received from service providers for unusual fluctuations to ensure that the prices represent a reasonable estimate of fair value.

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2013:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for	Significant Other Observable Inputs (Level 2) (in thousands)	Significant Unobservable Inputs (Level 3)	Total
	Identical Assets or Liabilities (Level 1)			
Liabilities:				
Commodity derivative contracts	\$ —	\$ (7,967)	\$ —	\$(7,967)
Total	\$ —	\$ (7,967)	\$ —	\$(7,967)

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The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2012:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for			
	Identical Assets or	Significant Other Observable Inputs	Significant Unobservable Inputs	
	Liabilities (Level 1)	(Level 2)	(Level 3)	Total
	(in thousands)			
Liabilities:				
Commodity derivative contracts	\$ —	\$ (8,790)	\$ —	\$(8,790)
Total	\$ —	\$ (8,790)	\$ —	\$(8,790)

## 14. Commitments

Our aggregate annual commitments, other than our loans payable, as of December 31, 2013 were as follows:

	Total	Payments Due by Year					
		2014	2015	2016	2017	2018	Thereafter
				(in thousands)			
Leases and other	\$5,602	\$2,546	\$903	\$299	\$99	\$33	\$1,722

Normal operations purchase arrangements are excluded from the table as they are discretionary or being performed under contracts which are cancelable immediately or with a 30-day notice period.

We lease office space in Dallas, Texas, Bulgaria and Turkey. We also lease apartments in Turkey and Dallas, as well as operations yards in Turkey. Rent expense for the years ended December 31, 2013, 2012 and 2011 was \$3.3 million, \$3.5 million and \$3.4 million, respectively.

## 15. Contingencies

### Selmo

We are involved in litigation with persons who claim ownership of a portion of the surface at the Selmo oil field in Turkey. These cases are being vigorously defended by TEMI and Turkish governmental authorities. We do not have enough information to estimate the potential additional operating costs we would incur in the event the purported surface owners' claims are ultimately successful. Any adjustment arising out of the claims will be recorded when it becomes probable and measurable.

### Morocco

In the second quarter of 2012, we were notified that the Moroccan government may seek to recover approximately \$5.5 million in contractual obligations under our Tselfat exploration permit work program. In February 2013, the Moroccan government drew down our \$1.0 million bank guarantee that was put in place to ensure our performance of the Tselfat exploration permit work program. Although we believe that the bank guarantee satisfies our contractual obligations, we recorded \$5.0 million in accrued liabilities relating to our Tselfat exploration permit during 2012 for this contingency.

### Aglen

In the second quarter of 2012, we were notified that the Bulgarian government may seek to recover approximately \$2.0 million in contractual obligations under our Aglen exploration permit work program. Due to the Bulgarian government's January 2012 ban on fracture stimulation and related activities, the government recognized a force majeure event under the terms of the exploration permit. Although we invoked force majeure, we have recorded \$2.0 million in accrued liabilities relating to our Aglen exploration permit during 2012 for this contractual obligation.

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### ***Direct Petroleum***

In July 2013, we entered into a second amendment (the “Amendment”) to the Purchase Agreement with Direct. Pursuant to the Amendment, we issued 351,074 common shares to Direct as partial payment of certain liquidated damages due under the Purchase Agreement. The number of shares was calculated by dividing \$2.5 million by the volume weighted average price per share of our common shares on the NYSE MKT for the ten trading days prior to July 2, 2013.

The parties also agreed that Direct is not eligible for any liquidated damages relating to the coring of the Etropole shale formation, which resulted in the reversal of the \$5.0 million contingent liability recorded in 2011, which we recognized in our consolidated statement of comprehensive income (loss) under the caption “Revaluation of contingent consideration.”

The Amendment sets forth a new obligation to drill and test the Deventci-R2 well by May 1, 2014. In the event that we do not meet the drilling and testing obligations by May 1, 2014, the Amendment requires us to issue an additional \$2.5 million in common shares (the “Additional Liquidated Damages”) to Direct. As such, the \$2.5 million contingent liability, recorded in 2011, remained as of December 31, 2013. In addition, the Amendment provides that we will issue \$7.5 million in common shares, less the Additional Liquidated Damages, if any, if the Deventci-R2 well is a commercial success (as defined in the Purchase Agreement) on or prior to May 1, 2016. We will record any provision for this contingent consideration when it is estimable and probable. As of December 31, 2013, we did not record a contingent liability for this contingent consideration.

Additionally, the Amendment provides that if the Bulgarian government issues a production concession over the Stefenetz Concession Area, Direct will be entitled to a payment of \$10.0 million in common shares, or a pro rata amount if the production concession is less than 200,000 acres. We do not have enough information to estimate the potential contingent liability we would incur in the event the Bulgarian government issues a production concession over the Stefenetz Concession Area. Any adjustment will be recorded when it becomes probable and estimable.

## **16. Related party transactions**

### ***Equity transactions***

On September 1, 2010, we issued 730,000 common share purchase warrants to Dalea Partners, LP (“Dalea”) pursuant to a credit agreement with Dalea. The common share purchase warrants had an exercise price of \$60.00 per share, and expired on September 1, 2013. Dalea is an affiliate of Mr. Mitchell.

### ***Sale of oilfield services business***

On June 13, 2012, we closed the sale of our oilfield services business, which was substantially comprised of our wholly owned subsidiaries Viking International Limited (“Viking International”) and Viking Geophysical Services, Ltd. (“Viking Geophysical”), to a joint venture owned by Dalea and funds advised by Abraaj Investment Management Limited for an aggregate purchase price of \$168.5 million, consisting of approximately \$157.0 million in cash and a \$11.5 million promissory note from Dalea. The promissory note is payable five years from the date of issuance or earlier upon the occurrence of certain specified events, including an initial public offering by the joint venture. Upon the consummation of an initial public offering by the joint venture and the prior approval of Dalea, we can elect to convert the outstanding balance of the promissory note, including accrued interest, into the number of shares offered in the initial public offering equal to such outstanding balance divided by the per share purchase price paid by the public in the initial public offering. The promissory note bears interest at a rate of 3.0% per annum and is guaranteed by Mr. Mitchell.

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### *Service transactions*

Effective May 1, 2008, we entered into a service agreement, as amended (the “Service Agreement”), with Longfellow Energy, LP (“Longfellow”), Viking Drilling LLC (“Viking Drilling”), MedOil Supply, LLC and Riata Management, LLC (“Riata Management”). Mr. Mitchell and his wife own 100% of Riata Management. In addition, Mr. Mitchell, his wife and his children indirectly own 100% of Longfellow. Riata Management owns 100% of MedOil Supply, LLC. Dalea owns 85% of Viking Drilling. Under the terms of the Service Agreement, we pay, or are paid, for the actual cost of the services rendered plus the actual cost of reasonable expenses on a monthly basis.

Effective January 1, 2011, our wholly owned subsidiary, TEMI, entered into an accommodation agreement under which it leased rooms, flats and office space at a resort hotel owned by Gundem Turizm Yatirim ve Isletme A.S. (“Gundem”), a Turkish company controlled by Mr. Mitchell. Under the accommodation agreement, TEMI leases six rooms at the hotel and pays the TRY equivalent of \$6,000 per month.

On August 23, 2011, the Company’s wholly owned subsidiary, TransAtlantic Petroleum (USA) Corp. (“TransAtlantic USA”), entered into an office lease with Longfellow to lease approximately 5,300 square feet of corporate office space in Addison, Texas. The initial lease term under the lease commenced on July 1, 2013, the date that TransAtlantic USA subleased a portion of its previous office space in Dallas, Texas (the “Commencement Date”). The lease expires five years after the Commencement Date, unless earlier terminated in accordance with the lease. During the initial lease term, TransAtlantic USA will pay monthly rent of \$6,625 to Longfellow plus, utilities, real property taxes and liability insurance. Prior to the Commencement Date, no rent, utilities, real property taxes and/or liability insurance were required to be paid to Longfellow under the lease.

On June 13, 2012, we entered into separate master services agreements with each of Viking International, Viking Petrol Sahasi Hizmetleri AS (“VOS”) and Viking Geophysical in connection with the sale of our oilfield services business to a joint venture owned by Dalea and funds managed by Abraaj Investment Management Limited. Pursuant to the master services agreements with Viking International and VOS, we are entitled to receive certain oilfield services and materials, including, but not limited to, drilling rigs and fracture stimulation that are needed for our operations in Bulgaria and Turkey. Pursuant to the master services agreement with Viking Geophysical, we are also entitled to receive geophysical services and materials that are needed for our operations in those countries. Each master services agreement is for a five-year term. Currently, we can contract for services and materials on a firm basis and, to the extent that we do not contract for all of their services or materials, Viking International, VOS and Viking Geophysical are allowed to contract with third parties for any remaining capacity.

On June 13, 2012, we entered into a transition services agreement with Viking Services Management, Ltd. (“Viking Management”) in connection with the sale of our oilfield services business to a joint venture owned by Dalea and funds managed by Abraaj Investment Management Limited. Pursuant to the transition services agreement, we agreed to provide certain administrative services, including, but not limited to, continued use of certain of our employees and independent contractors, a guarantee of a lease for flats in Turkey, Turkish tax or legal advice and services, office space in Istanbul, Turkey, information technology support and certain software or licenses to Viking Management. In addition, Viking Management agreed to cause its subsidiaries to provide us with the continued use of certain office space in Tekirdag, Turkey. In the third quarter of 2012, we entered into an addendum to the transition services agreement whereby Viking Management agreed to cause its subsidiaries to provide us with the continued use of certain equipment yards in the Thrace Basin and in southwestern Turkey. The addendum will terminate on April 1, 2014. The transition services agreement has a two-year term. Viking Management agreed to use commercially reasonable efforts to eliminate its need for such services as soon as practicable following the entry into the agreement.

On April 5, 2013 (the “First Floor Commencement Date”), TransAtlantic USA entered into an office lease with Longfellow to lease approximately 4,700 square feet of additional corporate office space in Addison, Texas. The initial lease term commenced on the First Floor Commencement Date and expires five years after the First Floor

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Commencement Date, unless earlier terminated in accordance with the lease. For the first year of the lease, TransAtlantic USA will pay monthly rent of \$7,533 to Longfellow plus, utilities, real property taxes and liability insurance.

For the years ended December 31, 2013 and 2012, we incurred capital and operating expenditures of \$85.7 million and \$73.8 million, respectively, related to our various related party agreements.

The following table summarizes related party accounts receivable and accounts payable as of December 31, 2013 and December 31, 2012:

	December 31,	December 31,
	2013	2012
	(in thousands)	
<i>Related party accounts receivable:</i>		
Viking International master services agreement	\$ 939	\$ 313
Riata Management Service Agreement	65	—
Dalea promissory note	—	106
Total related party accounts receivable	<u>\$ 1,004</u>	<u>\$ 419</u>
<i>Related party accounts payable:</i>		
Viking International master services agreement	\$ 15,956	\$ 15,467
Viking Geophysical master services agreement	6,800	—
Riata Management Service Agreement	334	167
Total related party accounts payable	<u>\$ 23,090</u>	<u>\$ 15,634</u>

## 17. Discontinued operations

### *Discontinued operations in Morocco*

On June 27, 2011, we decided to discontinue our operations in Morocco. We have substantially completed the process of winding down our operations in Morocco. We have presented the Moroccan segment operating results as discontinued operations for all periods presented.

### *Discontinued operations of oilfield services business*

On June 13, 2012, we closed the sale of our oilfield services business, which was substantially comprised of our wholly owned subsidiaries Viking International and Viking Geophysical, to a joint venture owned by Dalea and funds advised by Abraaj Investment Management Limited for an aggregate purchase price of \$168.5 million, consisting of approximately \$157.0 million in cash and a \$11.5 million promissory note from Dalea. The transaction was approved by a special committee of our board of directors after the receipt of a fairness opinion solely for the benefit of the special committee, which was subject to certain assumptions and limitations as provided in such opinion. The promissory note is payable five years from the date of issuance or earlier upon the occurrence of certain specified events, including an initial public offering by the joint venture. Upon the consummation of an initial public offering by the joint venture and the prior approval of Dalea, we can elect to convert the outstanding balance of the promissory note, including accrued interest, into the number of shares offered in the initial public offering equal to such outstanding balance divided by the per share purchase price paid by the public in the initial public offering. The promissory note bears interest at a rate of 3.0% per annum and is guaranteed by Mr. Mitchell. We used a portion of the net proceeds from the sale to pay off our \$73.0 million credit agreement with Dalea, our \$11.0 million credit facility with Dalea, our \$0.9 million promissory note with Viking Drilling and our \$1.8 million credit agreement with a Turkish bank. In addition, we used a portion of the net proceeds from the sale of our oilfield services business to pay down approximately \$45.2 million in outstanding indebtedness under our Amended and Restated Credit Facility. We have presented the oilfield services segment operating results as discontinued operations for the years ended December 31, 2013 and 2012.

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The assets and liabilities held for sale at December 31, 2013 and 2012 were as follows:

	December 31, 2013	(in thousands)	December 31, 2012
Cash	\$	23	\$ 93
Other assets <sup>(1)</sup>		513	1,526
Total assets held for sale	\$	536	\$ 1,619
Accrued expenses and other liabilities		7,559	8,416
Total liabilities held for sale	\$	7,559	\$ 8,416

(1) Other assets consist primarily of \$0.5 million and \$1.5 million of restricted cash at December 31, 2013 and December 31, 2012, respectively.

Our operating results from discontinued operations for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	2013	2012 (in thousands)	2011
Total revenues	\$ —	\$ 19,956	\$ 28,419
Total costs and expenses	(505)	(24,682)	(70,265)
Total other income (expense)	63	(357)	2,732
Loss from discontinued operations before income taxes	(442)	(5,083)	(39,114)
Gain on disposal of discontinued operations	—	35,999	—
Income tax provision	—	(8,297)	(4,255)
Net (loss) income from discontinued operations	<u>\$(442)</u>	<u>\$ 22,619</u>	<u>\$(43,369)</u>

## 18. Subsequent events

**Reverse Stock Split** . On March 4, 2014, the Company's shareholders approved a 1-for-10 reverse stock split, which became effective March 6, 2014. Pursuant to the reverse stock split, all shareholders of record received one common share for each ten common shares owned (subject to minor adjustments as a result of fractional shares). The reverse stock split reduced the issued and outstanding common shares from 374,026,984 to 37,402,698. U.S. GAAP requires that the reverse stock split be applied retrospectively to all periods presented. As a result, all common share transactions described herein have been adjusted to reflect the 1-for-10 reverse stock split.

**Idil Farm-Out** . In February 2014, our wholly owned subsidiary, TransAtlantic Turkey, and Selsinsan Petrol Maden T.O. San ve Tic. Ltd. Sti. ("Selsinsan") entered into a farm-out agreement with Onshore Petroleum Company AS ("Onshore"), a private oil and gas company. Pursuant to the agreement, Onshore will fund 100% of our initial exploration well, up to \$3.5 million, on the Idil license in southeastern Turkey. Expenses over \$3.5 million will be split equally between us and Onshore. In exchange, TransAtlantic Turkey and Selsinsan will assign Onshore a 50% interest in the Idil license.

**TRANS ATLANTIC PETROLEUM LTD.**  
**Supplemental Information**  
**(unaudited)**

**Supplemental quarterly financial data**

The following table summarizes results for each of the four quarters in the years ended December 31, 2013 and 2012.

	<u>March 31,</u>	<u>June 30,</u>	<u>September 30,</u>	<u>December 31,</u>
		(in thousands, except per share data)		
<b>For the year ended December 31, 2013:</b>				
Revenues	\$34,044	\$ 30,516	\$ 32,345	\$ 33,922
Net income (loss) <sup>(2)</sup>	2,939	2,903	(4,973)	(14,582)
Comprehensive income (loss)	103	(10,640)	(15,599)	(24,550)
Basic and diluted net income (loss) per common share from continuing operations <sup>(1)</sup>	\$ 0.08	\$ 0.08	\$ (0.13)	\$ (0.39)
<b>For the year ended December 31, 2012:</b>				
Revenues	\$36,671	\$ 34,428	\$ 34,815	\$ 37,994
Net (loss) income	(3,627)	25,106	6,994	(12,227)
Comprehensive income (loss)	9,736	26,247	10,140	(7,653)
Basic and diluted net (loss) income per common share from continuing operations <sup>(1)</sup>	\$ (0.04)	\$ 0.23	\$ 0.01	\$ (0.38)

- (1) The sum of the individual quarterly net income (loss) amounts per share may not agree with year-to-date net income (loss) per share as each quarterly computation is based on the net income or loss for that quarter and the weighted-average number of shares outstanding during that quarter.
- (2) See Note 15 regarding the revaluation of contingent consideration which was recorded during the three months ended June 30, 2013.

**Supplemental oil and natural gas reserves information**

As required by the FASB and SEC, the standardized measure of discounted future net cash flows (the “Standardized Measure”) presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10% to proved reserves. We do not believe the Standardized Measure provides a reliable estimate of the Company’s expected future cash flows to be obtained from the development and production of its oil and natural gas properties or of the value of its proved oil and natural gas reserves. The Standardized Measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year-to-year as prices change.

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, revisions to existing reserves estimates may occur from time to time. Although every reasonable effort is made to ensure reserves estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

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Proved reserves are those quantities of oil and natural gas that 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. We engaged DeGolyer & MacNaughton to prepare our reserves estimates comprising 100% of our estimated proved reserves (by volume) at December 31, 2013.

The following unaudited schedules are presented in accordance with required disclosures about oil and natural gas producing activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies.

All of our proved reserves are located in Turkey, and all prices are held constant in accordance with SEC rules.

Oil and natural gas prices used to estimate reserves were computed by applying the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 2013, 2012 and 2011. The oil and natural gas prices used to estimate reserves are shown in the table below.

	12-Month Average Price	
	Oil (per Bbl)	Natural Gas (per Mcf)
2013	\$102.07	\$ 9.92
2012	\$108.66	\$ 8.74
2011	\$108.00	\$ 7.18

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The following table sets forth our estimated net proved reserves (natural gas converted to Mboe by dividing Mmcf by six), including changes therein, and proved developed reserves:

### Disclosure of reserves quantities

	Oil (Mbbl)	Natural Gas (Mmcf)	Total (Mboe)
<b>Total proved reserves</b>			
<i>December 31, 2010</i>	12,936	22,425	16,673
Acquisitions	1	5,620	938
Extensions and discoveries	33	468	111
Revisions of previous estimates	(864)	(10,633)	(2,636)
Sales volumes	(891)	(4,657)	(1,667)
<i>December 31, 2011</i>	<u>11,215</u>	<u>13,223</u>	<u>13,419</u>
Extensions and discoveries	1,794	3,055	2,303
Revisions of previous estimates	(2,540)	423	(2,470)
Sales volumes	(949)	(4,238)	(1,655)
<i>December 31, 2012</i>	<u>9,520</u>	<u>12,463</u>	<u>11,597</u>
Extensions and discoveries	1,563	2,652	2,005
Revisions of previous estimates	(436)	3,436	137
Sales volumes	(933)	(3,512)	(1,518)
<i>December 31, 2013</i>	<u>9,714</u>	<u>15,039</u>	<u>12,221</u>
<b>Proved developed reserves</b>			
<i>December 31, 2011</i>			
Proved developed producing	4,284	6,564	5,378
Proved developed non-producing	<u>1,089</u>	<u>3,956</u>	<u>1,748</u>
Total	5,373	10,520	7,126
<i>December 31, 2012</i>			
Proved developed producing	4,241	5,228	5,112
Proved developed non-producing	<u>910</u>	<u>2,887</u>	<u>1,391</u>
Total	5,151	8,115	6,503
<i>December 31, 2013</i>			
Proved developed producing	4,540	7,189	5,738
Proved developed non-producing	<u>335</u>	<u>3,261</u>	<u>879</u>
Total	4,875	10,450	6,617
<b>Proved developed reserves</b>			
As of December 31, 2011	5,373	10,520	7,126
As of December 31, 2012	5,151	8,115	6,503
As of December 31, 2013	4,875	10,450	6,617
<b>Proved undeveloped reserves</b>			
As of December 31, 2011	5,842	2,703	6,293
As of December 31, 2012	4,369	4,348	5,094
As of December 31, 2013	4,839	4,589	5,604

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### *Standardized measure of discounted future net cash flows*

The standardized measure of discounted future net cash flows relating to estimated proved reserves as of December 31, 2013, 2012 and 2011 are shown in the table below.

	2013	2012 <sup>(1)</sup> (in thousands)	2011
Future cash inflows	\$1,141,775	\$1,143,346	\$1,306,844
Future production costs	(190,337)	(227,876)	(246,566)
Future development costs	(131,643)	(93,267)	(63,805)
Future income tax expense	(127,971)	(122,582)	(171,592)
Future net cash flows	691,824	699,621	824,881
10% annual discount for estimated timing of cash flows	(196,055)	(221,712)	(293,084)
Standardized measure of discounted future net cash flows related to proved reserves	<u>\$ 495,769</u>	<u>\$ 477,909</u>	<u>\$ 531,797</u>

- (1) During the second quarter of 2013, we discovered during our review procedures associated with our mid-year reserves analysis, that the future lease operating expenses used in our 2012 reserves calculation were overstated. This resulted in an immaterial understatement of the present value of the Standardized Measure as of December 31, 2012. The correction resulted in a proved reserves volume increase of approximately 19 Mboe, related to one of our oil fields where the economic life exceeds our remaining lease term. For the year ended December 31, 2012, this change in volumes had a negligible impact on the consolidated financial statements.

### *Changes in the standardized measure of discounted future net cash flows*

The following are the principal sources of changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2013, 2012 and 2011.

	2013	2012 <sup>(1)</sup> (in thousands)	2011
Standardized measure, January 1,	\$ 477,909	\$ 531,797	\$ 438,367
Net change in sales and transfer prices and in production (lifting) costs related to future production	(7,868)	(594)	244,980
Changes in future estimated development costs	(73,753)	(66,178)	(34,401)
Sales and transfers of oil and natural gas during the period	(108,674)	(116,477)	(108,915)
Net change due to extensions and discoveries	112,814	124,643	5,684
Net change due to purchases of minerals in place	—	—	48,017
Net change due to revisions in quantity estimates	7,678	(133,637)	(134,997)
Previously estimated development costs incurred during the period	47,252	50,810	54,943
Accretion of discount	56,376	64,584	52,254
Other	(12,070)	(10,644)	(15,604)
Net change in income taxes	(3,895)	33,605	(18,531)
Standardized measure, December 31,	<u>\$ 495,769</u>	<u>\$ 477,909</u>	<u>\$ 531,797</u>

- (1) During the second quarter of 2013, we discovered during our review procedures associated with our mid-year reserves analysis, that the future lease operating expenses used in our 2012 reserves calculation were overstated. This resulted in an immaterial understatement of the present value of the Standardized Measure as of December 31, 2012. The correction resulted in a proved reserves volume increase of approximately 19 Mboe, related to one of our oil fields where the economic life exceeds our remaining lease term. For the year ended December 31, 2012, this change in volumes had a negligible impact on the consolidated financial statements.

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### Capitalized costs related to oil and natural gas producing activities

Our capitalized costs for oil and natural gas properties consisted of the following:

	<u>Turkey</u>	<u>Other</u> (in thousands)	<u>Total</u>
<i>As of December 31, 2013</i>			
Oil and natural gas properties			
Proved	\$260,232	\$ 625	\$260,857
Unproved	51,273	3,119	54,392
Total oil and natural gas properties	311,505	3,744	315,249
Less accumulated depletion	(96,388)	(570)	(96,958)
Net oil and natural gas properties capitalized costs	\$215,117	\$3,174	\$218,291
<i>As of December 31, 2012</i>			
Oil and natural gas properties			
Proved	\$229,462	\$2,036	\$231,498
Unproved	68,938	—	68,938
Total oil and natural gas properties	298,400	2,036	300,436
Less accumulated depletion	(73,589)	(510)	(74,099)
Net oil and natural gas properties capitalized costs	\$224,811	\$1,526	\$226,337
<i>As of December 31, 2011</i>			
Oil and natural gas properties			
Proved	\$172,917	\$1,691	\$174,608
Unproved	70,393	—	70,393
Total oil and natural gas properties	243,310	1,691	245,001
Less accumulated depletion	(44,870)	(457)	(45,327)
Net oil and natural gas properties capitalized costs	\$198,440	\$1,234	\$199,674

### Costs incurred in oil and natural gas property acquisition, exploration and development

Costs incurred in oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	<u>Turkey</u>	<u>Other</u> (in thousands)	<u>Total</u>
<i>For the year ended December 31, 2013</i>			
Acquisitions of properties			
Proved	\$ —	\$ —	\$ —
Unproved	6,750	—	6,750
Exploration	40,258	2,742	43,000
Development	47,252	—	47,252
Total costs incurred	\$ 94,260	\$ 2,742	\$ 97,002
<i>For the year ended December 31, 2012</i>			
Acquisitions of properties			
Proved	\$ —	\$ —	\$ —
Unproved	—	—	—
Exploration	36,465	—	36,465
Development	43,824	867	44,691
Total costs incurred	\$ 80,289	\$ 867	\$ 81,156
<i>For the year ended December 31, 2011</i>			
Acquisitions of properties			
Proved	\$ 14,526	\$ 1,200	\$ 15,726
Unproved	16,131	25,840	41,971
Exploration	22,534	—	22,534
Development	52,711	192	52,903
Total costs incurred	\$105,902	\$27,232	\$133,134

**EXHIBIT INDEX**

- 2.1 Stock Purchase Agreement, dated March 15, 2012, by and among TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd., Longe Energy Limited, TransAtlantic Petroleum (USA) Corp., TransAtlantic Petroleum Cyprus Limited, Viking International Limited, Viking Geophysical Services, Ltd., Viking Oilfield Services SRL and Dalea Partners, LP. (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 10, 2012).
- 3.1 Certificate of Continuance of TransAtlantic Petroleum Ltd., dated October 1, 2009 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
- 3.2 Altered Memorandum of Continuance of TransAtlantic Petroleum Ltd., dated March 4, 2014 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated March 6, 2014, filed with the SEC on March 6, 2014).
- 3.3 Amended Bye-Laws of TransAtlantic Petroleum Ltd., dated March 4, 2014 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated March 6, 2014, filed with the SEC on March 6, 2014).
- 4.1 Amended and Restated Registration Rights Agreement, dated December 30, 2008, by and between TransAtlantic Petroleum Corp. and Riata Management, LLC (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated December 30, 2008, filed with the SEC on January 6, 2009).
- 4.2 Registration Rights Agreement, dated February 18, 2011, by and between TransAtlantic Petroleum Ltd. and Direct Petroleum Exploration, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated February 18, 2011, filed with the SEC on February 24, 2011).
- 4.3 Specimen Common Share certificate (incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K dated March 4, 2014, filed with the SEC on March 6, 2014).
- 10.1 Service Agreement, effective as of May 1, 2008, by and among TransAtlantic Petroleum Corp., Longfellow Energy, LP, Viking Drilling, LLC, Longe Energy Limited and Riata Management, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 6, 2008, filed with the SEC on February 12, 2009).
- 10.2 Amendment to Service Agreement, effective as of October 1, 2008, by and among TransAtlantic Petroleum Corp., Longfellow Energy, LP, Viking Drilling, LLC, Longe Energy Limited, MedOil Supply LLC and Riata Management, LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 6, 2008, filed with the SEC on February 12, 2009).
- 10.3 Domestic Crude Oil Purchase/Sale Agreement, dated as of January 26, 2009, by and between Türkiye Petrol Rafinerileri A.Ş. and TransAtlantic Exploration Mediterranean International Pty. Ltd. (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
- 10.4† Executive Employment Agreement, effective January 1, 2008, by and between TransAtlantic Petroleum Corp. and Jeffrey S. Mecom (incorporated by reference to Exhibit 4.8 to the Company's Annual Report on Form 20-F (File No. 000-31643), filed with the SEC on May 14, 2008).
- 10.5† TransAtlantic Petroleum Corp. 2009 Long-Term Incentive Plan (incorporated by reference to Appendix B to the Definitive Proxy Statement filed by TransAtlantic Petroleum Corp. with the SEC on April 30, 2009).
- 10.6† Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated June 16, 2009, filed with the SEC on June 22, 2009).

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- 10.7 Amended and Restated Credit Agreement, dated as of May 18, 2011, by and between DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri İnşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd., TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors, the lenders party thereto from time to time, and Standard Bank Plc and BNP Paribas (Suisse) SA, as joint mandated lead arrangers and joint bookrunners, and Standard Bank Plc as letter of credit issuer, administrative agent, collateral agent and technical agent (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated May 17, 2011, filed with the SEC on May 19, 2011).
- 10.8 Amendment No. 1 to the Amended and Restated Credit Agreement, dated as of August 4, 2011, by and between Amity Oil International Pty. Ltd., DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri İnşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd. and TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors, and Standard Bank Plc as administrative agent and as collateral agent (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 9, 2011).
- 10.9 Amendment No. 2 to the Amended and Restated Credit Agreement, dated as of September 14, 2011, by and between Amity Oil International Pty. Ltd., DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri İnşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd. and TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors and Standard Bank Plc as administrative agent and collateral agent (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 9, 2011).
- 10.10 Office Lease, dated August 23, 2011, by and between TransAtlantic Petroleum (USA) Corp. and Longfellow Energy, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated August 23, 2011, filed with the SEC on August 25, 2011).
- 10.11† Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated July 13, 2011, filed with the SEC on July 19, 2011).
- 10.12 Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking International Limited (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
- 10.13 Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
- 10.14 Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Geophysical Services, Ltd. (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
- 10.15 Transition Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum, Ltd. and Viking Services Management, Ltd. (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
- 10.16 Convertible Promissory Note made by Dalea Partners, LP to the order of TransAtlantic Petroleum Ltd., dated June 13, 2012 in the principal sum of \$11,500,000 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).

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10.17	Amendment No. 3 to the Amended and Restated Credit Agreement, dated as of November 21, 2012, by and between Amity Oil International Pty. Ltd., DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri İnşaat Sanayive Ticaret A.S., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd. and TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors and Standard Bank Plc as administrative agent and collateral agent (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K, filed with the SEC on May 16, 2013).
10.18	Office Lease, dated April 5, 2013, by and between TransAtlantic Petroleum (USA) Corp. and Longfellow Energy, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated May 8, 2013, filed with the SEC on May 14, 2013).
21.1*	Subsidiaries of the Company.
23.1*	Consent of KPMG LLP.
23.2*	Consent of KPMG Canada.
23.3*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Chief Executive Officer of the Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the Chief Financial Officer of the Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of the Chief Executive Officer of the Company, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer of the Company, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of DeGolyer and MacNaughton, dated February 28, 2014.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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† Management contract or compensatory plan arrangement.

\* Filed herewith.

\*\* Furnished herewith.

Subsidiaries of TransAtlantic Petroleum Ltd.  
March 1, 2014

<u>Subsidiary</u>	<u>Jurisdiction of Incorporation</u>
Amity Oil International Pty Ltd	Australia
Incremental Petroleum Pty Ltd	Australia
TransAtlantic Australia Pty Ltd	Australia
TransAtlantic Exploration Mediterranean International Pty Ltd	Australia
TransAtlantic (Holdings) Australia Pty Ltd	Australia
Anschutz Morocco Corporation	Bahamas
Direct Petroleum Morocco, Inc.	Bahamas
DMLP, Ltd.	Bahamas
Talon Exploration, Ltd.	Bahamas
TransAtlantic Maroc, Ltd.	Bahamas
TransAtlantic Turkey, Ltd.	Bahamas
TransAtlantic Worldwide, Ltd.	Bahamas
TransAtlantic Holdings, Ltd.	Bahamas
Longe Energy Limited	Bermuda
Thrace Basin Natural Gas (Turkiye) Corporation	British Virgin Islands
Direct Petroleum Bulgaria EOOD	Bulgaria
TransAtlantic Petroleum Cyprus Limited	Cyprus
TransAtlantic Petroleum (USA) Corp.	Delaware
MOS Viking SARL	Morocco
TransAtlantic Worldwide Romania SRL	Romania
Petrogas Petrol Gaz ve Petrokemya Urunleri Insaat Sanayive Ticaret A.S.	Turkey
TransAtlantic Petroleum Ukraine LLC	Ukraine

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors  
TransAtlantic Petroleum Ltd.:

We consent to the incorporation by reference in the registration statement (No. 333-162814) on Form S-8 of TransAtlantic Petroleum Ltd. (the Company) of our reports dated March 13, 2014, with respect to the consolidated balance sheets of TransAtlantic Petroleum Ltd. as of December 31, 2013 and 2012, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for the two-year period ended December 31, 2013, and all related financial statement schedules, and the effectiveness of internal control over financial reporting as of December 31, 2013, which reports appear in the December 31, 2013 Annual Report on Form 10-K of TransAtlantic Petroleum Ltd.

Our report dated March 13, 2014, on the effectiveness of internal control over financial reporting as of December 31, 2013, expresses an opinion that the Company did not maintain effective internal control over financial reporting as of December 31, 2013 because of the effect of material weaknesses on the achievement of the objectives of the control criteria and contains an explanatory paragraph that states that the following material weaknesses were identified and included in management's assessment in Item 9A of the Company's December 31, 2013 Annual Report on Form 10-K:

- The Company has not designed and implemented effective internal controls over remeasurement and translation of its foreign subsidiaries' account balances.
- The Company has not designed and implemented effective internal controls that sufficiently consider all information necessary to ensure proper classification and presentation within its consolidated financial statements.

/s/ KPMG LLP  
Dallas, Texas  
March 13, 2014

## CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM



**KPMG LLP**  
205-5th Avenue SW  
Suite 3100, Bow Valley Square 2  
Calgary AB  
T2P 4B9

Telephone (403) 691-8000  
Fax (403) 691-8008  
[www.kpmg.ca](http://www.kpmg.ca)

To the Board of Directors of TransAtlantic Petroleum Ltd.

We consent to the incorporation by reference in the Registration Statement on Form S-8 (File No. 333-162814) of TransAtlantic Petroleum Ltd. of our report dated March 23, 2012 (except for Note 1 dated March 13, 2014) on the consolidated statements of comprehensive loss, equity and cash flows of TransAtlantic Petroleum Ltd. for the year ended December 31, 2011, which report appears in the Form 10-K of TransAtlantic Petroleum Ltd. for the year ended December 31, 2013.

/s/ KPMG LLP  
Chartered Accountants

Calgary, Canada  
March 13, 2014

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.  
KPMG Canada provides services to KPMG LLP.

**KPMG Confidential**

**DeGolyer and MacNaughton**

5001 Spring Valley Road  
Suite 800 East  
Dallas, Texas 75244

March 13, 2014

TransAtlantic Petroleum Ltd.  
16803 Dallas Parkway  
Addison, Texas 75001

Ladies and Gentlemen:

We hereby consent to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm under the heading “Glossary of Selected Oil and Natural Gas Terms”, “Part I. – Item 1. Business” and “Part I – Item 2. Properties” of the Annual Report on Form 10-K for the year ended December 31, 2013, of TransAtlantic Petroleum Ltd. (“TransAtlantic”) to be filed with the U.S. Securities and Exchange Commission on or about March 17, 2014 (the “Annual Report”), including any amendments thereto, and to the inclusion of our third-party letter report dated February 28, 2014, containing our opinion on the proved, probable and possible reserves attributable to certain properties owned by TransAtlantic as of December 31, 2013.

We hereby further consent to the incorporation by reference of the foregoing in the Registration Statement on Form S-8 (No. 333-162814) of TransAtlantic.

Very truly yours,

/s/ DeGOLYER and MaCNAUGHTON

DeGOLYER and MacNAUGHTON  
Texas Registered Engineering Firm F-716

## CERTIFICATION

I, N. Malone Mitchell 3rd, certify that:

1. I have reviewed this Annual Report on Form 10-K of TransAtlantic Petroleum Ltd.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 13, 2014

/s/ N. Malone Mitchell 3rd

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N. Malone Mitchell 3rd  
Chief Executive Officer

# CERTIFICATION

I, Wil F. Saqueton, certify that:

1. I have reviewed this Annual Report on Form 10-K of TransAtlantic Petroleum Ltd.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 13, 2014

/s/ Wil F. Saqueton

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Wil F. Saqueton  
Chief Financial Officer

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,  
AS ADOPTED PURSUANT TO SECTION 906  
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of TransAtlantic Petroleum Ltd. (the "Company") for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, N. Malone Mitchell 3rd, Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

- (1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 13, 2014

/s/ N. Malone Mitchell 3rd  
\_\_\_\_\_  
N. Malone Mitchell 3rd  
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to TransAtlantic Petroleum Ltd. and will be retained by TransAtlantic Petroleum Ltd. and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,  
AS ADOPTED PURSUANT TO SECTION 906  
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of TransAtlantic Petroleum Ltd. (the “Company”) for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-K”), I, Wil F. Saqueton, Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

- (1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 13, 2014

\_\_\_\_\_  
/s/ Wil F. Saqueton  
Wil F. Saqueton  
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to TransAtlantic Petroleum Ltd. and will be retained by TransAtlantic Petroleum Ltd. and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

**DeGolyer and MacNaughton**  
5001 Spring Valley Road  
Suite 800 East  
Dallas, Texas 75244

February 28, 2014

TransAtlantic Petroleum Ltd.  
16803 Dallas Parkway, Suite 200  
Addison, Texas 75001

Gentlemen:

Pursuant to your request, we have conducted an independent evaluation, completed on February 28, 2014, to serve as a reserves audit of the extent and value of the proved, probable, and possible oil, natural gas, and condensate reserves, as of December 31, 2013, of certain properties owned by TransAtlantic Petroleum Ltd. (TransAtlantic) in Turkey and Bulgaria. TransAtlantic has represented that these properties account for 100 percent, on a net equivalent barrel basis, of TransAtlantic's net proved, probable, and possible reserves, as of December 31, 2013. The net proved, probable, and possible reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by TransAtlantic.

Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2013. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by TransAtlantic after deducting interests owned by others. Only net reserves are reported herein.

Gas reserves estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas produced from the reservoir after reduction for shrinkage resulting from field separation, processing, fuel use, and flare available to be delivered into a gas pipeline for sale. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.70 pounds per square inch absolute (psia). Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation.

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Values of proved, probable, and possible reserves shown herein are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves adjusted for net profits (where applicable). Future net revenue is defined as the future gross revenue less direct operating expenses, capital costs, abandonment costs, and net profits, where applicable. Direct operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization.

Estimates of oil, natural gas, and condensate reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with TransAtlantic personnel, from TransAtlantic files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by TransAtlantic with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

### **Methodology and Procedures**

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves

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Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, other engineering methods were used to estimate recovery factors. In such case, an analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

In certain cases, when the previously named methods could not be used, reserves or certain elements of reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

The fields have been grouped into three asset groups based on economic considerations: the Thrace Basin Natural Gas Company (TBNGC) asset group, the core TransAtlantic properties (TAT) asset group, and the Edirne asset group (consisting of Edirne field). All fields are subject to a royalty of 12.5 percent. The TBNGC asset group is subject to an additional 1.0-percent overriding royalty interest, except for Alibey field which has a 0.5-percent overriding royalty interest. Certain wells in TAT and Edirne asset groups are also subject to a net profits

DeGolyer and MacNaughton

interest of 5 percent. Net reserves quantities reported herein reflect the appropriate quantity reductions for royalty interests and overriding royalty interests, as well as the quantity reduction yielded from the calculated revenue associated with the net profits payable.

### **Definition of Reserves**

Petroleum reserves included in this report are classified by degree of proof as proved, probable, or possible. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

*Proved oil and gas reserves* – Proved oil and gas reserves are those quantities of oil and 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

*Probable reserves* – Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (iv) See also guidelines in paragraphs (iv) and (vi) of the definition of possible reserves.

*Possible reserves* – Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (iii) of the proved oil and gas reserves definition, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

*Developed oil and gas reserves* – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

*Undeveloped oil and gas reserves* – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.
- (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

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The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Probable and possible reserves in this report have not been adjusted in consideration of these additional risks and therefore are not comparable with proved reserves.

### **Primary Economic Assumptions**

The following economic assumptions were used for estimating existing and future prices and costs:

#### *Oil, Condensate, and Natural Gas Prices*

Prices used in this evaluation were based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. An average reference oil price during this period is Brent at 108.63 United States dollars (U.S.\$) per barrel. The average oil and condensate prices used to estimate reserves herein were as follows: U.S.\$55.38 per barrel in Bulgaria, U.S.\$103.71 per barrel in AG field, U.S.\$103.50 per barrel in Alibey field, U.S.\$102.82 per barrel in Arpatepe field, U.S.\$91.99 per barrel in Goksu field, U.S.\$81.28 per barrel in Kazanci field, U.S.\$103.00 per barrel in Molla field, and U.S.\$102.98 per barrel in Selmo field. The overall weighted-average oil price in this report was U.S.\$102.07. An average reference gas price during this period is the United Kingdom National Balancing Point Index of U.S.\$10.93 per million British thermal units. The average gas prices used in this report were as follows: U.S.\$10.35 per thousand cubic feet (Mcf) for TBNGC asset group, U.S.\$9.30 per Mcf for the Edirne asset group, U.S.\$3.80 per Mcf for Bulgaria, U.S.\$8.76 per Mcf for the Bakuk field, U.S.\$10.03 per Mcf for the CAB and DAK fields, and U.S.\$9.30 per Mcf for the remaining fields in TAT asset group. The overall weighted-average gas price in this report was U.S.\$9.92 per Mcf. These prices were held constant for the lives of the properties.

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*Net Profits Interest*

As represented by TransAtlantic, there is a 5-percent net profits interest burden for certain wells in the AG, Alpulu, CAB, DAK, Edirne, Karapurcek, and REDY fields. Where applicable, the net profits reduced TransAtlantic's ownership of reserves and revenue values.

*Operating Expenses and Capital Costs*

Estimates of operating expenses based on current expenses were used for the lives of the properties with no increases in the future based on inflation. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changes in operating conditions. Future capital expenditures were estimated using current values and were not adjusted for inflation.

*Abandonment Costs*

Abandonment costs were provided by TransAtlantic. These costs were estimated using current values and were not adjusted for inflation. Abandonment costs herein include well abandonment only. Also, TransAtlantic has represented that it will relinquish operation of the Selmo field to the Turkish Government at the end of June 2025, and therefore will not be responsible for abandonment costs pertaining to wells in the Selmo field that produce beyond June 2025.

*Royalty and Taxes*

All fields are subject to a royalty of 12.5 percent. Fields in the TBNGC asset group are subject to an additional 1.0-percent overriding royalty interest, except for the Alibey field, which has an 0.5-percent overriding royalty interest. Certain wells in the Edirne field are subject to a third-party carried net revenue

## DeGolyer and MacNaughton

interest of 2.625 percent. TransAtlantic has represented that there are no production taxes to be paid in Turkey or Bulgaria. No other taxes, including income taxes for Turkey, Bulgaria, Canada, or the United States, were considered in this evaluation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2013, oil, condensate, and gas reserves estimated herein. The reserves estimated in this report can be produced under current regulatory guidelines.

### **Summary of Oil and Gas Reserves and Revenue**

The estimates of net proved, probable, and possible reserves, as of December 31, 2013, attributable to the interests owned by TransAtlantic in Turkey and Bulgaria, of the properties evaluated herein, are summarized as follows, expressed in barrels (bbl) or thousands of cubic feet (Mcf):

	Estimated by DeGolyer and MacNaughton as of December 31, 2013		
	Net Oil (bbl)	Net Condensate (bbl)	Net Sales Gas (Mcf)
<b>Proved</b>			
Developed	4,874,071	0	10,450,760
Undeveloped	4,839,710	0	4,587,639
<b>Total Proved</b>	<b>9,713,781</b>	<b>0</b>	<b>15,038,399</b>
<b>Probable</b>	8,119,930	0	23,030,272
<b>Possible</b>	16,877,453	0	78,204,982

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

## DeGolyer and MacNaughton

The estimated revenue and expenditures attributable to TransAtlantic's interests in Turkey and Bulgaria in the proved, probable, and possible net reserves, as of December 31, 2013, of the properties appraised under the aforementioned assumptions concerning future prices and costs are summarized as follows, expressed in U.S. dollars (U.S.\$):

	Estimated by DeGolyer and MacNaughton as of December 31, 2013				
	Proved			Probable (U.S.\$)	Possible (U.S.\$)
	Developed (U.S.\$)	Undeveloped (U.S.\$)	Total (U.S.\$)		
Future Gross Revenue	603,011,171	538,763,685	1,141,774,856	1,050,707,014	2,507,219,882
Production Taxes	0	0	0	0	0
Operating Expenses	105,405,019	80,775,708	186,180,727	110,147,870	168,687,018
Capital Costs	4,143,989	127,499,433	131,643,422	139,141,578	165,713,850
Abandonment Costs	2,791,942	298,514	3,090,456	613,688	327,336
Net Profits	(273,377)	(792,841)	(1,066,218)	(982,316)	(23,463,392)
Future Net Revenue	490,396,844	329,397,189	819,794,033	799,821,562	2,149,028,286
Present Worth at 10 Percent	364,282,144	228,241,426	592,523,570	521,412,270	1,282,337,800

## Notes:

1. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.
2. Future income tax expenses were not taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved, probable, and possible reserves, estimated future net revenue from proved, probable, and possible reserves, and present worth of estimated future net revenue from proved, probable, and possible reserves of oil, condensate, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10 (a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (5), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

## DeGolyer and MacNaughton

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in TransAtlantic. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of TransAtlantic. DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton  
DeGOLYER and MacNAUGHTON  
Texas Registered Engineering Firm F-716

/s/ Lloyd W. Cade, P.E.

[SEAL]

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Lloyd W. Cade, P.E.  
Senior Vice President  
DeGolyer and MacNaughton

**CERTIFICATE of QUALIFICATION**

I, Lloyd W. Cade, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to TransAtlantic dated February 28, 2014, and that I, as Senior Vice President, was responsible for the preparation of this report.
2. That I attended Kansas State University, and that I graduated with a Bachelor of Science degree in Mechanical Engineering in the year 1982; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers; and that I have in excess of 31 years of experience in oil and gas reservoir studies and evaluations.
3. That DeGolyer and MacNaughton or its officers have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of TransAtlantic Petroleum Ltd. or affiliate thereof.

SIGNED: February 28, 2014

[SEAL]

/s/ Lloyd W. Cade, P.E.  
\_\_\_\_\_  
Lloyd W. Cade, P.E.  
Senior Vice President  
DeGolyer and MacNaughton