TRANSATLANTIC PETROLEUM LTD.
Form 10-K
March 23, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

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

TRANSATLANTIC PETROLEUM LTD.

(Exact name of registrant as specified in its charter)

Bermuda	**None**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
Akmerkez B Blok Kat 5-6 Nispetiye Caddesi 34330 Etiler, Istanbul, Turkey	**None**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: +90 212 317 25 00

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

Title of each class	**Name of each exchange on which registered**
Common shares, par value $0.01	NYSE Amex

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

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

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 þ

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 þ 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 þ 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	þ

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 þ

The aggregate market value of common shares, par value $0.01 per share, held by non-affiliates of the registrant, based on the last sale price of the common shares on June 30, 2011 (the last business day of the registrant s most recently completed second fiscal quarter), was approximately $361.3 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 15, 2012, there were 366,534,449 common shares outstanding.

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 2012 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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TRANSATLANTIC PETROLEUM LTD.

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2011

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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 c

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. 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 and provinces 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; the ability to consummate the sale of our oilfield services business as contemplated or at all; the effect of the sale of our oilfield services business to our costs and expenses; 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 (including the sale of our oilfield services business); future cash flows, uses of cash flows, collectibility 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.

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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.

4D seismic. Geophysical data that depicts the subsurface strata in three dimensions at different times in the productive life of a reservoir. 4D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 3D 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.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent. Boe is not included in the DeGolyer and MacNaughton reserve 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.

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. 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.

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.

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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.

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.

Net production. The amount of production of oil or natural gas after deducting royalties and working interests owned by third parties.

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 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.

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.

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.

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.

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, 2011 and 2010 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.

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.

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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

General

We are an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty and tax rates to exploration and production companies. We hold interests in developed and undeveloped oil and natural gas properties in Turkey, Bulgaria and Romania. As of March 1, 2012, we held approximately 5.4 million net onshore acres. As of March 1, 2012, approximately 40% of our outstanding common shares were beneficially owned by N. Malone Mitchell, 3rd, the chairman of our board of directors and chief executive officer.

Based on the reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, our estimated proved reserves at December 31, 2011 were 13.4 net Mmboe, of which 84% were oil. Of these estimated proved reserves, 53% were proved developed reserves. As of December 31, 2011, the PV-10 of our proved reserves was $645.8 million.

Divestiture of Our Oilfield Services Business

In 2008, we changed our operating strategy from a prospect generator to a vertically integrated project developer. To execute that strategy, we acquired a large portfolio of exploration acreage in Turkey, Bulgaria, Romania and Morocco, as well as producing properties in Turkey. At the same time, we established a significant and comprehensive oilfield services business through our wholly owned subsidiaries, Viking International Limited (Viking International) and Viking Geophysical Services, Ltd. (Viking Geophysical). These subsidiaries provided a full range of services and materials to our exploration and production business, substantially reducing our need to rely on third party service providers. As a result, we were able to introduce North American drilling and completion technology to Turkey, lower our drilling and operating costs and control the timing of the development of our properties.

In 2011, we determined that we did not have sufficient capital to grow both the exploration and production and oilfield services businesses at the desired rate. As a result, in May 2011, our board of directors formed a special committee comprised of four independent directors (the Special Committee) to evaluate strategic alternatives related to our oilfield services business, and in September 2011, we engaged an independent financial advisor to advise us in this process.

On March 15, 2012, we signed a stock purchase agreement to sell our oilfield services business, which is substantially comprised of our wholly owned subsidiaries Viking International and Viking Geophysical (collectively, Viking), to Dalea Partners, LP (Dalea , an affiliate of N. Malone Mitchell, 3rd, the Company s Chairman and Chief Executive Officer) for an aggregate purchase price of $164.0 million, consisting of $152.5 million in cash, subject to a net working capital adjustment, and a $11.5 million promissory note from Dalea. The promissory note will be payable five years from the date of issuance or earlier upon the occurrence of certain specified events, will bear interest at a rate of 3.0% per annum and will be guaranteed by Mr. Mitchell. Prior to closing, Dalea expects to assign the stock purchase agreement to a joint venture owned by Dalea and funds advised by Abraaj Investment Management Limited (an affiliate of Abraaj Capital Holdings Limited, one of the leading private equity groups investing in emerging markets). The sale of Viking is subject to the approval of regulatory authorities, the receipt of equity financing by the buyer and other customary closing conditions. The stock purchase agreement also contains customary representations, warranties, covenants and termination rights.

The transaction was approved by the Special Committee 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.

Contractually, the effective date of the sale of Viking will be April 1, 2012, regardless of when the actual closing occurs. The closing is anticipated to occur during the second quarter of 2012. The purchase price for Viking will be increased by the amount (if any) that the net working capital of Viking is greater than zero and will be decreased by the amount (if any) that the net working capital of Viking is less than zero. We intend to use approximately $4.0 million of the cash consideration to repay (i) the outstanding balance on our amended and restated note payable from Viking International to Viking Drilling, LLC (Viking Drilling), and (ii) the outstanding balance of a secured credit agreement entered into by Viking International to fund the purchase of vehicles. In addition, we intend to use a portion of the remaining cash proceeds to repay our credit agreement with Dalea, and we may use the remaining cash proceeds along with existing cash to repay some or all of the outstanding indebtedness under our amended and restated senior secured credit facility (the Amended and Restated Credit Facility) with Standard Bank Plc (Standard Bank) and BNP Paribas (Suisse) SA (BNP Paribas).

Pursuant to the stock purchase agreement, we and Viking are prohibited from soliciting any acquisition proposals from a third party or furnishing any non-public information with respect to Viking. Notwithstanding the foregoing, Viking s representatives may respond to unsolicited inquiries, but solely for the purpose of communicating that we are not able to entertain the unsolicited offer.

In conjunction with the stock purchase agreement, Dalea has agreed to extend the maturity of its credit agreement with us until the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of Viking or (y) two business days after demand by Dalea. Interest on the Dalea credit agreement will cease to accrue from April 1, 2012 until the closing date of the sale of Viking. If the closing does not occur, the abated interest will be reinstated.

Pursuant to the stock purchase agreement, we will enter into a transition services agreement for the benefit of Viking. In addition, we will enter into a five-year master services agreement with Viking International and Viking Geophysical, which will provide us with continued access to Viking s equipment and services. Under the master services agreement, we will be entitled to most favored terms if Viking provides terms or benefits to any third party customers that are more favorable than terms or benefits provided to us in the master services agreement. In addition, Viking will have the right to bid or quote on any new drilling services and will have the right to bid at a price equal to 99% of the lowest third party bid for such drilling services.

For a period of five years following the closing of the stock purchase agreement, we will be prohibited from competing in the oilfield services business with Viking in a specified geographic area. In addition, for five years after the closing, if we acquire any interest in any person generally engaged in the oilfield services business in a specified geographic area, Dalea will generally have the right to purchase such business from us. For five years after closing, Dalea will also be prohibited from competing with us in the oil and natural gas exploration and production business and will also be required to offer to us any interest they acquire in any person engaged in the oil and gas exploration and production business within a specified geographic area.

Focus on Our Exploration and Production Business

We anticipate that the divestiture of our oilfield services business will provide the capital necessary to substantially strengthen our balance sheet. In addition, we expect this proposed transaction to result in a streamlined administrative structure, which we believe will result in a reduction in our general and administrative expense. Finally, we expect that the sale of our oilfield services business will allow us to focus on our core business, which is the acquisition, exploration, development and production of oil and natural gas.

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To that end, we plan to continue the exploration and development of our shallow and deep natural gas fields in the Thrace Basin and our Selmo and Arpatepe oil fields in 2012. We plan to appraise the 2011 oil discovery on our Molla exploration licenses and the 2010 gas discovery on our Bakuk exploration license, and we will continue to drill exploration wells on other licenses. As part of our exploration and development strategy, we plan to continue our efforts to reduce exploration risk by seeking joint venture partners for our exploration acreage in Turkey, Bulgaria and Romania.

Development of Unconventional Resources in Turkey

We plan to continue our strategy of applying modern drilling and completion techniques, such as modern 3D seismic acquisition, reentry into shallow wells, fracture stimulation and directional drilling, to our properties in Turkey, especially in the Thrace Basin. We began our first fracture stimulations of natural gas wells in the Thrace Basin in northwestern Turkey in the fourth quarter of 2010, and by the end of 2011 we began to experience positive results.

To date, we have tested geological structures in just four of our Thrace Basin licenses, identifying approximately 38,500 acres with the right geological structure and depositional factors in place to support a successful resource development program (the Tekirdag Field Area). We intend to continue testing geological structures across our entire Thrace Basin acreage position and are optimistic that we can increase our drilling inventory. We expect that the stacked pays of the Thrace Basin will support multi-stage completions, which we expect to commence testing during 2012. We will continue to test the Mezardere sands structure during the first quarter of 2012, which, if successful, could add additional acreage in the Thrace Basin to our unconventional drilling portfolio.

In southeastern Turkey, we plan to drill and test the Dadas shale formation, which underlies several of our exploration licenses. In addition, we plan to drill our first horizontal well in the fractured Mardin carbonate formations that are found in southeastern Turkey.

Recent Developments

Direct Petroleum Acquisition. On February 18, 2011, our wholly owned subsidiary TransAtlantic Worldwide, Ltd. (TransAtlantic Worldwide) acquired Direct Petroleum Morocco, Inc. (Direct Morocco) and Anschutz Morocco Corporation (Anschutz), and our wholly owned subsidiary TransAtlantic Petroleum Cyprus Limited (TransAtlantic Cyprus) acquired Direct Petroleum Bulgaria EOOD (Direct Bulgaria). In addition, TransAtlantic Worldwide purchased from the seller, Direct Petroleum Exploration, Inc. (Direct), all of Direct s right, title and interest in the amounts due to Direct by each of Direct Morocco, Anschutz and Direct Bulgaria. As consideration for the acquisition, TransAtlantic Worldwide paid $2.4 million in cash to Direct, and we issued 8,924,478 of our common shares (at a deemed price of $3.15 per common share) to Direct in a private placement, for total consideration of $34.5 million. In addition, if certain post-closing milestones are achieved, we will issue additional consideration to Direct equal to: (i) $10.0 million worth of our common shares if the Deventci-R2 well in Bulgaria is a commercial success and (ii) $10.0 million worth of our common shares if Direct Bulgaria receives a production concession for a specified area in Bulgaria. Of this additional consideration, up to $10.0 million worth of our common shares would be due if we have not timely completed certain obligations regarding the drilling of the Deventci-R2 well and the coring of the Etropole shale formation. 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.

Amendment and Restatement of Senior Secured Credit Facility. On May 18, 2011, our wholly owned subsidiaries, DMLP, Ltd. (DMLP), Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş. (Petrogas), Talon Exploration, Ltd. (Talon Exploration), TransAtlantic Exploration Mediterranean International Pty Ltd (TEMI) and TransAtlantic Turkey, Ltd. (TAT) amended and restated our senior secured credit facility with Standard Bank and BNP Paribas to extend the maturity date to May 18, 2016, to include our wholly owned subsidiaries Amity Oil International Pty Ltd (Amity) and Petrogas as borrowers, and to increase the borrowing base. Following our semi-annual borrowing base redetermination on October 1, 2011, our borrowing base is currently $81.4 million. As of December 31, 2011, we had borrowed $78 million and had $3.4 million available for borrowing under the Amended and Restated Credit Facility.

Amendments of Dalea Credit Agreement. On May 18, 2011, we entered into a first amendment to our credit agreement, dated as of June 28, 2010, with Dalea to extend the maturity date of the credit agreement to December 31, 2011 and to increase the interest rate to match the interest rate payable under our Amended and Restated Credit Facility. On November 7, 2011, we entered into a second amendment to the Dalea credit agreement to extend the maturity date to the earlier of (i) March 31, 2012 or (ii) the sale of Viking. On March 15, 2012, we entered into a third amendment to the Dalea credit agreement to extend the maturity date until the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of Viking or (y) two business days after demand by Dalea.

Repayment of Short-Term Secured Credit Agreement. On May 24, 2011, we used a portion of the amounts borrowed under our Amended and Restated Credit Facility to repay a $30.0 million short-term secured credit agreement, dated as of August 25, 2010, between TransAtlantic Worldwide and Standard Bank, which was scheduled to mature on May 25, 2011.

TBNG Acquisition. On June 7, 2011, TransAtlantic Worldwide acquired all of the shares of Thrace Basin Natural Gas (Turkiye) Corporation (TBNG) from Mustafa Mehmet Corporation (MMC) in exchange for (i) the issuance of 18,500,000 of our common shares (at a deemed price of $2.05 per common share), (ii) the transfer of certain overriding royalty interests (ranging from 1.0% to 2.5% of the working interests owned by TBNG on specified exploration licenses) to MMC or an affiliate of MMC and (iii) the payment of $10.5 million in cash. TransAtlantic Worldwide applied a $10.0 million option fee it paid to MMC in November 2010 towards the purchase price at closing. Through the acquisition of TBNG, we acquired interests ranging from 25% to 41.5% in ten exploration licenses and four production leases as well as drilling rigs and oilfield service assets.

Discontinued Operations in Morocco. On June 27, 2011, we decided to discontinue our operations in Morocco. We have transferred our oilfield services equipment from Morocco to Turkey and are in the process of winding down our operations in Morocco.

Ban on Fracture Stimulation in Bulgaria. On January 18, 2012, the Bulgarian Parliament enacted legislation that bans fracture stimulation in the Republic of Bulgaria. As long as this legislation remains in effect, our exploration, development and production activities in Bulgaria will be significantly constrained. As a result of the ban, we have recorded an approximately $25.9 million impairment charge related to unproved oil and natural gas properties in Bulgaria, which we acquired in February 2011.

Sale of Viking International and Viking Geophysical. On March 15, 2012, we entered into a stock purchase agreement to sell Viking to Dalea for an aggregate purchase price of $164 million, subject to adjustment in certain limited circumstances. Please see Our Business Divestiture of Our Oilfield Services Business for additional information concerning the stock purchase agreement.

Dalea Credit Facility. On March 15, 2012, we entered into a $15.0 million credit facility with Dalea to provide us with additional liquidity for general corporate purposes until we complete the sale of Viking. If drawn, loans under the credit facility will accrue interest at a rate of three month LIBOR plus 5.5% per annum. Any proceeds received by us or any subsidiary from any debt financings (subject to certain specified exceptions) or from the sale of Viking, net of reasonable transaction and financing costs, must be used to repay amounts outstanding under the credit facility. If drawn, any outstanding borrowings must be repaid upon the earlier of (i) July 1, 2012 or (ii) the sale of Viking.

Changes in Executive Management. In May 2011, our board of directors appointed Mr. Mitchell as our chief executive officer. Mr. Mitchell is also the chairman of our board of directors and owned approximately 40% of our outstanding common shares as of March 1, 2012. In August 2011, our board of directors appointed Wil F. Saqueton as our vice president and chief financial officer, and in January 2012, our board of directors appointed Mustafa Yavuz as our chief operating officer.

Our Strengths

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

Significant Exploration Acreage. As of March 1, 2012, we held approximately 5.4 million net onshore acres in Turkey, Bulgaria and Romania. The majority of this onshore acreage is exploratory, and we will seek to develop a portion of this acreage through joint ventures or farm-out agreements with major industry players.

Strong and Experienced Management Team. Our management team, led by our chief executive officer, Mr. Mitchell, includes executives and managers with significant industry, operational and technical experience. Mr. Mitchell previously built Riata Energy, Inc. (now re-named SandRidge Energy, Inc.) into 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. On average, our operations management team has more than 25 years of industry experience and is integral in executing our growth strategy.

Growing Production and Cash Flow. We have increased our net production from 975 Mboe in 2010 to 1,667 Mboe in 2011. We expect continued production and cash flow growth through the development of our Thrace Basin, Selmo, Arpatepe and Molla properties in Turkey, general and administrative expense reductions and the integration of our recent acquisitions in Turkey.

Operations in Attractive Regions. We have focused our operations in countries that are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty and tax rates to exploration and production companies. Our production in Turkey is subject to a 12.5% royalty rate, and the corporate 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 2011, we realized average prices of $100.27 per Bbl for our oil production and $7.05 per Mcf for our natural gas production. We also expect that our properties in Bulgaria and Romania will operate under favorable economic terms. We expect that future production in Bulgaria and Romania will be subject to royalty rates ranging from 2.5% to 30% and 3.5% to 13.5%, respectively, and corporate tax rates of 10% and 16% after a one-year tax holiday, respectively.

Our Strategy

The following are key elements of our strategy:

Grow Production and Reserves in Turkey. We have completed a number of important acquisitions through which we have substantially grown our acreage and reserves and increased our production in Turkey. We acquired TBNG in June 2011, which brought additional acreage, production, personnel and equipment into our Turkish operations. We also plan to increase our oil and natural gas production in Turkey through continuous drilling in Selmo, Arpatepe and the Thrace Basin, the completion of pipelines to bring shut-in natural gas to market, the application of modern well stimulation techniques and the use of directional drilling.

Expand Drilling Inventory. In the Thrace Basin region of Turkey, we recently completed several 3D seismic surveys, which we are currently evaluating. We believe these surveys will significantly add to our conventional shallow acreage opportunities and define deeper, unconventional opportunities on large structures that have already been identified. We have also acquired and commenced additional 3D seismic surveys that identified a number of development and exploration locations in southern Turkey as well as shallow structural plays similar to those found in the Thrace Basin.

Apply Modern Drilling and Completion Techniques in Turkey. Historically, the oil and natural gas exploration and production industry in Turkey has not used modern drilling and completion techniques. We expect to expand our application of modern techniques to our properties in Turkey. Modern 3D seismic acquisition, re-entry into shallow wells, fracture stimulation possibilities and the potential for directional drilling all provide opportunities to significantly increase production and grow reserves. In the fourth quarter of 2010, we began our first fracture stimulations of natural gas wells in the Thrace Basin and oil wells at Selmo, and by the end of 2011 we began to experience positive results. We have also successfully fracture stimulated several oil wells in Selmo. We plan to continue our fracture stimulation program, particularly in the Thrace Basin, and anticipate that employing fracture stimulation techniques will result in the commercial development of reserves that would have not been commercial otherwise.

Reduce Exploration Risk Through Partnerships. We are currently seeking joint venture partners for our exploration acreage in Bulgaria, Romania and Turkey. Through farm-outs, we expect to accelerate development, mitigate exploration risk and reduce our share of capital commitments. In Turkey, we entered into an agreement with Shell Upstream Turkey BV (Shell) to farm-out a 60% working interest in our Sivas Basin licenses covering approximately 1.6 million acres. In Bulgaria, we entered into an agreement with LNG Energy, Ltd. (LNG) pursuant to which LNG funded the drilling of an exploration well to core and test the Etropole shale formation. In Romania, we are seeking a partner to drill and test an exploration well to test the Silurian shale potential on the Sud Craiova license.

Our Properties and Operations

Turkey

As of March 1, 2012, we held interests in 57 onshore exploration licenses and nine onshore production leases covering a total of 5.3 million gross acres (4.3 million net acres) in Turkey. As of December 31, 2011, we had total net proved reserves of 11,208 Mbbl of oil and 12,846 Mmcf of natural gas, net probable reserves of 4,801 Mbbl of oil and 12,622 Mmcf of natural gas and net possible reserves of 11,655 Mbbl of oil and 105,174 Mmcf of natural gas in Turkey. For 2011, we produced an average of approximately 4,542 net Boepd of oil and natural gas in Turkey. The following summarizes our core producing properties in Turkey:

Thrace Basin. 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. We have accumulated significant onshore acreage in the Thrace Basin, which is located in northwestern Turkey near Istanbul. In 2011, we shot 451 square kilometers of 3D seismic, 97 square kilometers of 4D seismic and 31 kilometers of 2D seismic in the Thrace Basin. We anticipate that these seismic surveys will significantly add to our conventional shallow acreage opportunities and define deeper, unconventional opportunities on large structures that have already been identified. In addition, we completed and commissioned a 20-kilometer, 10-inch pipeline connecting our Alpullu natural gas fields to an existing pipeline.

For 2011, our net production of natural gas was approximately 4,611 Mmcf, or approximately 12.6 Mmcf/d. For the fourth quarter of 2011, our net production of natural gas was approximately 1,553 Mmcf, or approximately 16.9 Mmcf/d. In 2011, we drilled eleven exploration wells and 12 additional development wells on our Thrace Basin properties. As of March 1, 2012, we had 206 producing wells on our Thrace Basin properties, and we plan to drill approximately 65 new wells and re-enter approximately 55 existing wellbores on our Thrace Basin properties in 2012.

Thrace Basin Frac 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. Our fracture stimulation activities are focused on our properties in the Thrace Basin in northwestern Turkey.

For the unconventional Mezardere formation in the Thrace Basin, a typical fracture stimulation procedure includes injecting between 10,000 and 60,000 gallons of fluid (which is gelled fresh water containing approximately 4% potassium chloride) that contain between 10,000 and 150,000 pounds of sand. The size of the fracture stimulation treatment is dependent on net pay thickness and the proximity of the hydrocarbon zones of interest to water bearing sands.

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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 is associated with fracture stimulation activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into our normal capital expenditure budget. Approximately $14.0 million of our 2012 capital expenditure budget is associated with our planned fracture stimulation activities.

The table below details our fracture stimulation results in the Thrace Basin through December 31, 2011, all of which were drilled on licenses owned by TBNG:

Well	Working Interest (%)	Frac Date	Net Pay (meters)	Porosity (%)	Unrestricted Test Rate (Mmcf/d)	Initial 7-Day Average (Mmcf/d)
Yazir-2, 1st stage	41.5%	7/18/2011	27	8.5	0.1	0.1
Yazir-2, 2nd stage	41.5%	8/1/2011	46	10	-	-
Kayi-15	41.5%	9/30/2011	20	17	0.6	0.5
BTD-2	41.5%	10/3/2011	9	16	4.3	3.3
Aydede-2	41.5%	11/22/2011	4	20	2.2	1.4
DTD-7	41.5%	11/28/2011	9	14	0.2	0.1
Kayi-14	41.5%	12/7/2011	13	17	5.0	3.7
Dogu Yagci-1	41.5%	12/12/2011	10	14	2.0	1.5
Aydede-1	41.5%	12/14/2011	10	15	0.9	0.7

These early results have provided important lessons for the design of our planned Thrace Basin frac program for 2012. There are also other potential target zones in stacked-pay intervals within these wells, and the successful results have set up a number of surrounding drilling and frac locations in the Mezardere unconventional formation. 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.

In addition, in the fourth quarter of 2011, we drilled the Pancarkoy-1 re-entry exploration well (100% working interest), which is our first test of deep, unconventional natural gas opportunities in the Thrace Basin. We put this well on production in March 2012. The well exhibited high initial gas rates during the initial flowback period but was followed by high water influx. We plan to fracture stimulate additional prospective formations uphole from the current producing formation. If successful, we expect this re-entry well would support offset locations to fully develop the structure in 2012 and would confirm that deep, unconventional natural gas opportunities exist on a number of similar structures in the Thrace Basin. We also recently drilled the Suleymaniye-2 exploration well (41.5% working interest) targeting the Osmancik and Mezardere formations on a license southwest of the Pancarkoy-1 well. The Suleymaniye-2 exploration well targeted a four-way structural high to a previously drilled well that generated natural gas shows in the targeted interval and is currently awaiting completion. The next well in the program, the DTD Deep-1 (41.5% working interest) was recently spud targeting four prospective intervals. The DTD Deep-1 well will be the first deep test in the Tekirdag Field Area and is on the same geological structure as our existing dataset of shallower re-entry fracs.

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 and 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, we have access to water resources which we believe will be adequate to execute our fracture stimulation program in 2012. We also employ procedures for environmentally friendly disposal of fluid recovered from fracture stimulation, including recycling approximately 50% of these fluids at a local waste treatment facility.

For more information on the risks of fracture stimulation, please read Item 1A. Risk Factors 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 Legislative and regulatory initiatives and increased public scrutiny relating to fracture stimulation could results in increased costs and additional operating restrictions or delays.

Southeastern Turkey. Substantially all of our oil production is concentrated in southeastern Turkey, primarily in the Selmo and Arpatepe oil fields. These properties are located within the Zagros fold belt, which encompasses the oil fields of Iran and Iraq.

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 2011, we drilled 13 development wells and performed nine fracture stimulations of existing wellbores on our Selmo production lease. For 2011, our net production of crude oil from the Selmo field was 838,615 Bbls at an average rate of approximately 2,298 Bbls per day. Turkiye Petrolleri Anonim Ortakligi (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. At March 1, 2012, we had 45 producing wells in the Selmo field, and we plan to drill approximately 15 wells at Selmo in 2012.

We hold a 50% working interest in the Arpatepe production lease. In 2011, we drilled two exploration wells and commenced drilling two additional development wells. The Kocahoyuk-1 exploration well encountered the target Bedinan sands formation low to the prognosis and was plugged and abandoned. The Arpatepe-4 exploration well encountered the target Bedinan sands formation, and we are currently evaluating the well. The Arpatepe-6 well was drilled and cased in January 2012 and is expected to commence production by April 2012. For 2011, our net production of crude oil from the Arpatepe field was 49,994 Bbls at an average rate of approximately 137 Bbls per day. At March 1, 2012, we had three producing wells in the Arpatepe field, and we plan to drill approximately three wells at Arpatepe in 2012.

We hold a 100% working interest in the Molla exploration license. In 2011, we completed the Goksu-1 well as a new field discovery in the Mardin group at approximately 5,500 feet. The Goksu-1 well had an initial flow rate of approximately 340 Bbls per day. Existing 2D seismic indicates the Goksu structure may be approximately 2,500 acres in extent. The Goksu-1 well was originally drilled in 2010 to test the Bedinan sands, which was unsuccessful, and the Silurian-aged Dadas shale, which tested natural gas and condensate at non-commercial rates from a vertical completion. We drilled the Goksu-2 appraisal well in December 2011, which had an initial flow rate of approximately 400 Bbls per day and produced more than 5,600 Bbls of oil during its first 20 days of production. The next well in this field, the Bahar-1, is expected to spud in March 2012, and will test both the Mardin formation and the Dadas shale. Following the Bahar-1, we plan to drill the Goksu-3 well in the second quarter of 2012. We believe this well will be the first horizontal well to test the fractured Mardin carbonate formations found in this region.

Central Basins. We have substantial exploration acreage in central Turkey. In February 2012, we entered into an agreement with Shell pursuant to which Shell will co-fund the acquisition of 1,000 kilometers of 2D seismic data and approximately 8,000 kilometers of airborne gravity gradiometry and magnetic data in Turkey s Sivas Basin, where we hold exploration licenses covering approximately 1.6 million acres. The agreement provides an option for Shell to farm in to the exploration licenses after it assesses the data collected. Up to two

initial exploration wells may be drilled in 2013 in accordance with the underlying work commitments for the Sivas Basin exploration licenses.

Bulgaria

We have submitted an application for a production concession covering approximately 160,000 acres over the northern portion of our former A-Lovech exploration permit, which expired in November 2011 (the Koynare Concession Area). The Koynare Concession Area contains the Deventci-R1 well, where we discovered a reservoir in the Jurassic-aged Orzirovo formation at a depth of approximately 13,800 feet, which the Bulgarian government has certified as a geologic discovery. As of March 1, 2012, the well was producing approximately 250 Mcf/d of natural gas on a limited test basis, which is sold to a compressed natural gas facility adjacent to the Deventci-R1 well. In November 2011, we commenced drilling an appraisal well, the Deventci-R2, on the Koynare Concession Area.

We have also submitted an application 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 for Etropole shale at a depth of approximately 12,500 feet, which the Bulgarian government has certified as a geologic discovery. 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. We collected more than 900 feet of core, which is currently under evaluation. If the well is successful and 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.

In January 2012, the Bulgarian Parliament enacted legislation that bans fracture stimulation in the Republic of Bulgaria. The legislation also restricts the injection of fluids into underground formations at pressures greater than approximately 300 pounds per square inch. As a result, we have temporarily suspended drilling and completion operations for the Deventci-R2 and Peshtene-R11 wells. Although we expect the Bulgarian government to clarify the legislation to allow for conventional drilling and to institute a set of procedures regulating the fracture stimulation of wells, we cannot be certain when or if this will occur. In the meantime, we and LNG are evaluating the core data and developing a conventional completion program for the Peshtene-R11 well.

Romania

As of March 1, 2012, we held a 50% non-operated working interest in the Sud Craiova onshore exploration license in western Romania. We and the operator of the license, Sterling Resources Ltd. (Sterling), have committed to participate in a 200 kilometer 2D seismic survey on the Sud Craiova license in 2012 and are currently seeking a farm-out partner to drill an exploration well to test the Silurian-aged shale formations present on the Sud Craiova license.

Current Operations

As of March 1, 2012, we were producing an aggregate of approximately 2,638 net Bbls of oil per day, primarily from the Selmo production lease, Arpatepe production lease and the Goksu exploration license, and approximately 14.5 net Mmcf/d of natural gas, primarily from our various Thrace Basin production leases and exploration licenses. As of March 1, 2012, we were engaged in the following drilling and exploration activities:

Turkey. We were drilling two wells at Selmo and one well at Arpatepe, and we were planning to commence drilling three wells in the Thrace Basin in March 2012, two of which will explore untested deep horizons in the Mezardere unconventional formation. In addition, we were planning to complete four wells on our Selmo and Arpatepe production leases and Thrace Basin licenses and preparing five wells in the Thrace Basin for fracture stimulation in March 2012.

Bulgaria. We were reviewing the core sample that we collected from the Peshtene-R11 well and developing a conventional completion program for the Peshtene-R11 well.

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Romania. We were seeking a farm-out partner to drill an exploration well to test the Silurian-aged shale formations present on the Sud Craiova license.

Planned Operations

We continue to actively explore and develop our existing oil and natural gas properties in Turkey and evaluate the opportunities for further activities in Bulgaria and Romania. Our success will depend in part on discovering additional hydrocarbons in commercial quantities and then bringing these discoveries into production. In 2012, we are focused on accomplishing the following objectives:

Increase Production. We plan to increase our oil and natural gas production in Turkey through the development of our Thrace Basin properties and our Selmo and Arpatepe oil fields, including through continuous conventional drilling in Selmo, Arpatepe and the Thrace Basin, the completion of pipelines to bring shut-in natural gas to market, the application of fracture stimulation techniques and the use of directional drilling.

Expand Fracture Stimulation Program. In 2011, our Thrace Basin fracture simulation program brought positive results and provided important lessons regarding frac design. We plan to expand our application of fracture stimulation techniques to additional properties in the Thrace Basin. We plan to continue our exploration of the deep, unconventional opportunities in the Thrace Basin, and we plan to drill and test the Dadas shale formation underlying several of our licenses in southeastern Turkey. We anticipate that employing fracture stimulation techniques will result in the commercial development of production and reserves that would have not been commercial otherwise.

Reduce Exploration Risk Through Partnerships. In an effort to increase the pace of exploration activity, share exploration risk, and reduce our share of the capital commitments necessary to carry forward the exploration of our extensive acreage position, we are currently seeking joint venture partners for our exploration acreage in Bulgaria, Romania and Turkey and plan to continue this effort in 2012.

Complete the Sale of Viking. We plan to complete the sale of Viking in 2012. Please see Our Business Divestiture of Our Oilfield Services Business for additional information.

We expect our capital expenditures for 2012 to be approximately $130.0 million. We expect capital expenditures during 2012 to consist of approximately $110.0 million of drilling and completion expense (over 90 gross wells), $15.0 million of seismic expense and $6.0 million on infrastructure expense. Approximately 65% of these anticipated expenditures will occur in the Thrace Basin in Turkey, devoted to developing conventional and unconventional natural gas production, building infrastructure and acquiring seismic data. Most of the remaining 35% of these anticipated expenditures will occur in southeastern Turkey, devoted to drilling developmental and exploratory oil wells at Selmo, Arpatepe, Molla and Bakuk. If cash on hand, borrowings from our Amended and Restated Credit Facility and cash flow from operations are not sufficient to fund our capital expenditures, then we will either curtail our discretionary capital expenditures or seek other funding sources. If we successfully complete the sale of our oilfield services business, we may use a portion of the net proceeds to pay down our Amended and Restated Credit Facility, thereby increasing our capacity to fund capital expenditures. Our projected 2012 capital expenditure budget is subject to change and could be reduced if we do not raise additional funds.

Exploration, Development and Production. We currently plan to execute the following drilling and exploration activities during 2012:

Turkey. We plan to drill approximately 92 gross wells, of which 39 will be fracture stimulated. In addition, we plan to fracture stimulate another 20 existing wellbores and perform conventional uphole recompletions in 35 existing wellbores on our Thrace Basin properties. We also plan to construct the infrastructure necessary to produce and sell oil and natural gas from the productive wells we drill.

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Bulgaria. We plan to complete our evaluation of the Peshtene-R11 exploration well core data and develop a conventional completion program for the well.

Romania. We are seeking a farm-out partner to drill an exploration well to test the Silurian-aged shale formations present on the Sud Craiova license.

Principal Capital Expenditures and Divestitures

The following table sets forth our principal capital expenditures during 2011 (in thousands of dollars):

Expenditure Type	Year Ended December 31, 2011
Oil and natural gas properties	$ 68,519
Equipment and other property	3,137
Subtotal	71,656
Acquisition of TBNG, net of cash received	46,584
Acquisition of Direct Bulgaria, net of cash received	34,200
Total capital expenditures	$ 152,440

There were no material capital divestitures during 2011.

Principal Markets

In accordance with the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 280, *Segment Reporting* (ASC 280), we currently have three reportable geographic segments: Bulgaria, Romania and Turkey. For financial information about our operating segments and geographic areas, refer to Note 14 Segment information to our consolidated financial statements.

Customers

Oil. During 2011, 93.9% 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 2011, we sold $84.3 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/Dörtyol 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.

Natural Gas. During 2011, 98.2% of our natural gas production was concentrated in the Thrace Basin in northwestern Turkey. Zorlu Dogal Gaz Ithalat Ihracat ve Toptan Ticaret A.S. (Zorlu), a privately owned natural gas distributor in Turkey, purchases natural gas production from certain of our Thrace Basin properties. During 2011, we sold $20.0 million of natural gas to Zorlu, representing 15.8% of our total revenues.

We sell all of our natural gas production from the licenses owned by Amity and Petrogas in the Thrace Basin to Zorlu pursuant to a framework agreement. We sell the natural gas at a price equal to a 15% discount to the Industrial Interruptible Tariff benchmark set by BOTAŞ. The framework agreement continues for so long as we deliver natural gas production from these licenses to Zorlu.

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Competition

Exploration, Development and Production. 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
- acquiring the equipment and 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 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.

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;
- 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;

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.

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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. We also store, transport and use explosive materials in certain of our oilfield services operations, which are also subject to special controls and regulatory regimes in certain countries in which we conduct our services.

Repatriation of Earnings. Currently, there are no restrictions on the repatriation of earnings or capital to foreign entities from Turkey, Bulgaria or Romania. 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, potentially resulting 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 operation 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. Recently, the government of Bulgaria enacted legislation that bans the fracture stimulation of oil and natural gas wells in Bulgaria and imposes large monetary penalties on companies that violate that ban. There is a risk that other jurisdictions in which we operate, including Turkey and Romania, 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 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.

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 28, 2016, 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. To date, the Ministry of Finance has given no indication that the Ministry: (i) would not extend the term of the assurance beyond 2016; or (ii) would allow the term of the assurance to expire; or (iii) would change the tax treatment afforded to exempted companies either before or after 2016. This treatment has recently been extended to March 31, 2035, and we are in the process of obtaining the requisite assurance documents.

We are required to pay an annual government fee (the AGF), which is determined on a sliding scale by reference to our authorised share capital and share premium account, with the minimum fee being $1,995 in Bermuda dollars and the maximum being $31,120 in 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 in the year to which the AGF is applicable and is based on the authorised share capital and share premium account as they stood at August 31st 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. Accordingly no stamp duty will be payable on our issuance of the notes.

Employees

As of March 1, 2012, we employed approximately 1,029 people and, through a service agreement with Longfellow Energy, LP (Longfellow), Viking Drilling, MedOil Supply, LLC and Riata Management, LLC (Riata), contracted for the services of approximately 21 additional people. As of December 31, 2011, approximately 55 of our employees at one of our Turkish subsidiaries were represented by collective bargaining agreements with the Turkish Employers Association of Chemical, Oil and Plastic Industries (KIPLAS) and the Petroleum, Chemical and Rubber Workers Union of Turkey (PETROL-IS). The collective bargaining agreements expired on January 31, 2012, and we have continued to honor the terms of the expired agreements for those employees. As of March 1, 2012, these employees are no longer represented by KIPLAS and PETROL-IS. 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 as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC.

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Executive Officers of the Registrant

Name	Age	Positions
N. Malone Mitchell, 3rd	50	Chairman of the Board of Directors and Chief Executive Officer
Mustafa Yavuz	49	Chief Operating Officer
Wil F. Saqueton	42	Vice President and Chief Financial Officer
Jeffrey S. Mecom	46	Vice President and Corporate Secretary

N. Malone Mitchell, 3rd 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.

Mustafa Yavuz has served as our chief operating officer since January 2012. He joined us in June 2011 in connection with our acquisition of TBNG. Mr. Yavuz joined TBNG in 1987 and served as TBNG s vice president and chief operating officer from 2004 to January 2012.

Wil F. Saqueton has served as our vice president and chief financial officer since August 2011. Mr. Saqueton previously served as our corporate controller from May 2011 until August 2011 and as our consultant from February 2011 until May 2011. Prior to joining us, 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 our corporate secretary since May 2006 and as a vice president since May 2007. Before joining us 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.

To the best of our knowledge, there are no arrangements or understandings between any officer and any other person, pursuant to which any person referred to above was selected as an officer.

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 2011, we generated a comprehensive loss of approximately $168.3 million and had $40.5 million of cash provided by operating activities. 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.

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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 the 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 any 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 initial estimates.

We will require significant capital to continue our exploration and development activities beyond June 30, 2012.

We may not have sufficient funds to continue our operations beyond June 30, 2012, the maturity date of our credit agreement with Dalea. If we are unable to finance our operations or successfully consummate the sale of our oilfield services business on acceptable terms or at all, our business, financial condition and results of operations may be materially and adversely affected.

Future cash flows and the availability of debt or equity financing will be subject to a number of factors, such as:

- the success of our prospects in Turkey, Bulgaria and Romania;
- success in finding and commercially producing reserves; and
- prices for oil and natural gas production.

Debt financing could lead to:

- a substantial portion of operating cash flow being dedicated to the payment of principal and interest;
- us being more vulnerable to competitive pressures and economic downturns; and
- restrictions on our operations.

If sufficient capital resources are not available, we might be forced to cease operations entirely, curtail developmental and exploratory drilling and other activities or be forced to sell some assets on an untimely or unfavorable basis, which would have a material adverse effect on our business, financial condition and results of operations.

The sale of our oilfield services business could increase our operating costs and expenses and negatively impact our ability to conduct our business.

Historically, we have relied upon our oilfield services business to provide services that are necessary to conduct our business. If the sale of our oilfield services business is successful, we will no longer own drilling rigs and oilfield services equipment, which will increase our operating costs and expenses. In addition, we could be subject to greater risks related to the availability and cost of drilling rigs and third party oilfield services in the future. Our historical reliance upon our oilfield services business in our operations and our limited ability to control certain costs and expenses following the consummation of the sale could materially adversely affect our business, financial condition and results of operations.

We need significant amounts of cash to repay our debt. If we are unable to generate sufficient cash to repay our debt, our business, financial condition and results of operations could be adversely affected.

As of December 31, 2011, the outstanding principal amount of our debt was $163.8 million, of which $5.0 million is classified as held for sale. Of this amount, $73.0 million under our credit agreement with Dalea is due upon the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of Viking or (y) two business days after demand by Dalea. We must generate sufficient amounts of cash to service and repay our debt. Our ability to generate cash will be affected by general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. Future borrowings may not be available to us under our Amended and Restated Credit Facility or from other lenders in amounts sufficient to pay our obligations as they mature or to fund other liquidity needs. In addition, disruptions in the credit and financial markets can constrain our access to capital and increase its cost. The inability to service, repay or refinance our indebtedness could adversely affect our financial condition and results of operations.

If future financing is not available to us when required, as a result of limited access to the credit or equity markets or otherwise, or is not available on acceptable terms, we may be unable to invest needed capital for our developmental and exploratory drilling and other activities, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our business, financial condition and results of operations.

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, 2011, as disclosed in Item 9A. Controls and Procedures. Failure to have effective internal controls could lead to a misstatement of our financial statements. 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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Our Amended and Restated Credit Facility and credit agreement with Dalea, as amended, contain 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 or our credit agreement with Dalea 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 and credit agreement with Dalea contain 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;
- dispose of all or substantially all of our assets;
- use the amounts borrowed for only certain specified purposes;
- declare or provide for any dividends or other payments or distributions;
- redeem or purchase any shares; or
- guarantee or permit the guarantee of 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 a default under the Amended and Restated Credit Facility.

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 DMLP, Amity, Petrogas, TEMI, Talon Exploration and TAT (collectively, the Borrowers) or any of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide (collectively, and together with TransAtlantic Petroleum Ltd., the Guarantors) 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.

An event of default under the credit agreement with Dalea includes, among other events, failure to make the payment of principal or interest when due, breach of certain covenants or conditions, the occurrence of an adverse material change in our financial condition, bankruptcy or insolvency, or a change of control. In the event of a default under the credit agreement, the lender can demand all amounts payable under the credit agreement to be immediately due and payable. In the event of bankruptcy or insolvency, all amounts payable under the credit agreement become immediately due and payable.

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

We depend on a limited number of key personnel who would be difficult to replace.

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.

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 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; and
- declines in oil and natural gas prices.

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.

We have concentrated current production of crude oil.

We derive substantially all of our crude oil production from the Selmo field in southeastern Turkey. TPAO and TUPRAS purchase all of our crude oil production from the Selmo field, which represented 66.4% of our total revenues in 2011. If either of these companies fails to purchase our production, our results of operations could be materially and adversely affected.

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

As of December 31, 2011, approximately 55 of our employees at one of our Turkish subsidiaries were represented by collective bargaining agreements with KIPLAS and PETROL-IS. The collective bargaining agreements expired on January 31, 2012, and we have continued to honor the terms of the expired agreements. As of March 1, 2012, KIPLAS and PETROL-IS no longer represent these employees. However, potential work disruptions from labor disputes with these employees could disrupt our business and adversely affect our financial condition and results of operations.

Our operations are primarily conducted in Turkey, Bulgaria and Romania, and we are subject to political, economic and other risks and uncertainties in these countries.

Our international operations are mainly performed in emerging markets such as Turkey, Bulgaria and Romania, which may expose us to greater risks than those associated with more developed markets. In total, these markets accounted for 99.9% and 99.8% of our operating revenue in 2011 and 2010, respectively. 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, 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;
- 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.

We currently derive substantially all of our oil revenue 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 or conditions 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.

We are involved in litigation over the ownership of a portion of the surface rights at the Selmo oil field in Turkey.

A substantial portion of our revenue for 2011 was generated from the sale of oil produced from the Selmo oil field in Turkey. Our subsidiary, TEMI, has been involved in litigation with persons who claim ownership of a portion of the surface rights of the Selmo field, which encompasses almost all of our producing wells at Selmo. We and the Turkish government are vigorously defending these cases. Although the litigation does not affect our ownership of the Selmo production lease, if this litigation is not resolved in our favor, our operations on the affected portions of the Selmo oil field could be materially disrupted. A material disruption to our operations at Selmo could have a material adverse effect on our business.

The occurrence of a financial crisis, such as the financial crisis in recent years, may impact our ability to obtain equity, debt or bank financing in the future and may adversely impact our operations.

Events in the financial markets in recent years had an adverse impact on the credit markets and, as a result, the availability of equity, debt or bank financing has become more expensive and difficult to obtain. Banks have been adversely affected by the financial crisis and have severely curtailed existing liquidity lines, increased pricing and introduced new and tighter borrowing restrictions to corporate borrowers, with extremely limited access to new facilities or for new borrowers. These factors could negatively impact our ability to access liquidity needed for our business in the longer term. These factors may impact our ability to obtain equity, debt or bank financing on terms commercially reasonable to us, if at all. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. The negative impact of these events may also include our inability to expand existing credit facilities or finance the acquisition of assets on favorable terms, if at all, or adversely impacting our operations or the trading price of our common shares.

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

For Canadian tax purposes, we were deemed, immediately before the completion of our 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.

We could be subject to Bermuda corporate taxes in the future.

We are a Bermuda exempted company and under current law, we are not subject to tax on profits, income or dividends, nor is there any capital gains tax applicable to us in Bermuda. Furthermore, we have received 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 shares, debentures or other obligations shall be exempt from the imposition of such tax until March 28, 2016. If the Ministry of Finance of Bermuda changes the tax treatment afforded to exempted companies, allows the terms of the assurance to expire or does not extend the term of assurance beyond 2016, we could be subject to Bermuda corporate taxes in the future, which could have a material adverse effect on our business, financial condition or results of operations.

Risks Related to the Oil and Natural Gas Industry

Reserve estimates depend on many assumptions that may turn out to be inaccurate.

Any material inaccuracies in our reserve 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.

We may not correctly evaluate reserve 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 Incremental Petroleum Limited, now called Incremental Petroleum Pty Ltd (Incremental), Talon Exploration, Amity, Petrogas, Direct Bulgaria, Anschutz, Direct Morocco 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.

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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:

- change in local and global 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.

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 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, 2011, approximately 47% of our total estimated net proved reserves were proved undeveloped reserves. Undeveloped reserves, by their nature, are significantly less certain than developed reserves. We also have a significant amount of unproved reserves at December 31, 2011. There is significant uncertainty attached to unproved reserve estimates, which include probable and possible reserves. 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.

Legislative and regulatory initiatives and increased public scrutiny relating to fracture simulation 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 natural gas production. Recently there has been increased public concern with regards to 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. For example, in January 2012, the government of Bulgaria enacted legislation that bans the fracture stimulation of oil and natural gas wells in Bulgaria and imposes large monetary penalties on companies that violate that ban. 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 legislative or regulatory initiatives placing restrictions on fracture stimulation activities, especially in Turkey, could impose operational delays, increased operations costs and additional related burdens on our exploration and production activities which could make it more difficult to perform fracture stimulation, cause a material decrease in the drilling of new wells and related servicing 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 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 which 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.

Drilling for oil and natural gas is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our 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 uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as flooding;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

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 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 regulation, 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 be in compliance in all material respects with all 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.

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 and oilfield services business.

We do not intend to insure against all risks. Our oil and natural gas exploration and production activities and oilfield services business 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 and shoreline 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;

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 currently carry general liability insurance and excess liability insurance with a combined annual limit of $31.0 million per occurrence and $45.0 million in the aggregate. These insurance policies contain maximum policy limits and are subject to customary exclusions and limitations. 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 and pollution 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 $1.0 million per occurrence. Our pollution insurance has a per occurrence and aggregate annual limit of $2.0 million and is subject to a $25,000 deductible per occurrence.

We will require our thirdparty service providers, including Viking International and Viking Geophysical, to sign master service agreements with us pursuant to which they will generally 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 will agree to indemnify our third-party service providers against claims made by us, our employees and our other contractors.

We will 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.

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 often 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
- acquiring the equipment and 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.

We may not be able to complete the exploration, development or production of any, or a significant portion of, the oil and natural gas interests covered by our leases or licenses before they expire.

Each license or lease under which we operate has a fixed term. We may be unable to complete our exploration, development or production efforts prior to the expiration of licenses or leases. Failure to obtain government approval for a license or lease, an extension of the license or lease, be granted a new exploration license or lease or the failure to obtain a license or lease covering a sufficiently large area would prevent or limit us from continuing to explore, develop or produce a significant portion of the oil and natural gas interests covered by the license or lease. The determination of the amount of acreage to be covered by the production license or lease is in the discretion of the respective governments.

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Political and economic instability or fundamental changes in the leadership or in the structure of the governments in the jurisdictions in which we operate could have a material negative impact on our company.

Our foreign property interests and foreign operations may be affected by political and economic risks. These risks include war and civil disturbances, political instability, currency restrictions and exchange rate fluctuations, labor problems and high rates of inflation. In addition, local, regional and world events could cause the jurisdictions in which we operate to change the petroleum laws, tax laws, foreign investment laws, or to revise their policies in a manner that renders our current and future projects unprofitable. Further, we are subject to risks in the foreign jurisdictions in which we operate of the nationalization of the oil and natural gas industry, expropriation of property or other restrictions and penalties on foreign-owned entities, which could render our projects unprofitable or could prevent us from selling our assets or operating our business. The occurrence of any such fundamental change could have a material adverse effect on our business, financial condition and results of operations.

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, 2012, 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 other shareholders.

The value of our common shares might 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, Romania 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.

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 shareholders investment in us.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Turkey

General. As of March 1, 2012, we held interests in 57 onshore exploration licenses and nine onshore production leases covering a total of approximately 5.3 million gross acres (approximately 4.3 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.

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The following is a map showing our interests in Turkey:

Reserves. As of December 31, 2011, we had total net proved reserves of 11,208 Mbbl of oil and 12,846 Mmcf of natural gas, net probable reserves of 4,801 Mbbl of oil and 12,622 Mmcf of natural gas and net possible reserves of 11,655 Mbbl of oil and 105,174 Mmcf of natural gas in Turkey.

Equipment. As of March 1, 2012, we leased equipment yards in Muratli, Diyarbakir and Tekirdag and owned equipment yards at Selmo, Tekirdag and Edirne. As of March 1, 2012, we owned eleven drilling rigs and five workover and completion rigs. We expect to sell these drilling rigs along with our oilfield services business.

Commercial Terms. Turkey s fiscal regime for oil and natural gas licenses is presently comprised of royalties and income tax. Royalties are at 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. The licenses have a four-year term but after the third year, a payment in the form of a bond must be made to extend the license if no new well has been drilled prior to that date. 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.

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 license grants exclusive rights over an area for the exploration for petroleum. 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 eight licenses within a district. Rentals are due annually based on the hectares under the license.

Once a discovery is made, the license holder applies to convert the area, not to exceed 25,000 hectares, to a lease. Under a lease, the lessee may produce oil and natural gas. The term of a lease is for 20 years. Annual rentals are due based on the hectares comprising the lease.

Thrace Basin. The following is a map showing our interests in the Thrace Basin in northwestern Turkey:

Edirne (Licenses 3839 and 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, 2012, we had 15 producing wells on the Edirne licenses, and we plan to drill approximately two wells on the Edirne licenses during 2012. We are the operator of Licenses 3839 and 4037, which expire in October 2014 and March 2013, respectively.

Alpullu (Production Lease 3599-4794 and License 4861). We own a 100% working interest in Production Lease 3599-4794 and License 4861, which cover approximately 3,158 acres and 117,000 acres, respectively. Upon the acquisition of Amity in August 2010, we commenced limited natural gas sales from the Alpullu production lease. As of March 1, 2012, we had seven producing wells on the Alpullu production lease, and we plan to drill approximately five wells during 2012 to further develop the Alpullu production lease and test structures on the Alpullu exploration license. We are the operator of Production Lease 3599-4794 and License 4861, which expire in September 2028 and December 2014, respectively.

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. Upon the acquisition of Amity in August 2010, we commenced limited natural gas sales from the Gocerler production lease. As of March 1, 2012, we had six producing wells on the Gocerler production lease and ten producing wells on License 4288. We plan to drill approximately three wells on the Gocerler production lease and approximately seven wells on License 4288 during 2012. TPAO is the operator of Production Lease 4200 and we are the operator of License 4288, which expire in March 2024 and August 2013, respectively.

Adatepe (Production Lease 3648-4959 and License 5016). We own a 50% working interest in Production Lease 3648-4959 and License 5016, which cover approximately 3,086 gross acres and 117,000 gross acres, respectively. Upon the acquisition of Amity in August 2010, we commenced limited natural gas sales from the Adatepe production lease. As of March 1, 2012, we had seven producing wells on the Adatepe production lease. We are the operator of Production Lease 3648-4959 and License 5016, which expire in September 2031 and January 2017, respectively.

Malkara (Licenses 4094 and 4532). We own a 100% working interest in Licenses 4094 and 4532, which cover an aggregate of approximately 242,000 acres. The licenses are subject to a 50% farm-in right to Valeura Energy, Ltd. (Valeura) in return for the completion of certain work commitments. We are the operator of Licenses 4094 and 4532, which expire in September 2013 and January 2013, respectively.

Banarli (License 3864). We own a 50% working interest in License 3864, which covers approximately 96,000 gross acres. As of March 1, 2012, we had one producing well on the Banarli license. We are the operator of License 3864, which expires in April 2012. We have applied for a production lease over a portion of the Banarli license.

Tekirdag (Production Leases 3860 and 3861 and 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, 2012, we had 61 producing wells on the Tekirdag production leases and 93 producing wells on the Tekirdag license. We plan to drill approximately two wells on the Tekirdag production leases and approximately 11 wells on the Tekirdag license during 2012. We are the operator of Production Leases 3860 and 3861 and License 3931, which expire in December 2023, December 2021 and November 2012, respectively.

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, 2012, we had ten producing wells on the Hayrabolu production lease, and we plan to drill approximately two wells on the Hayrabolu production lease in 2012. We are the operator of Production Lease 2926, which expires in February 2020.

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, 2012, we had three producing wells on the Gelindere production lease. We are the operator of Production Lease 3659, which expires in June 2017.

Gazioglu (License 3934). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3934, which covers approximately 56,000 gross acres. As of March 1, 2012, we had seven producing wells on the Gazioglu exploration license, and we plan to drill approximately six wells on the Gazioglu exploration license during 2012. We are the operator of License 3934, which expires in November 2012.

Karakopek (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. We are the operator of License 3858, which expires in May 2012. Based on the Senova-l gas discovery well that we drilled on License 3858 in 2011, we are applying to extend the expiration date of License 3858 to May 2015.

Tatarli (License 3734). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3734, which covers approximately 121,000 gross acres. As of March 1, 2012, we had 12 producing wells on the Tatarli exploration license. We plan to drill approximately 12 wells on the Tatarli exploration license during 2012. We are the operator of License 3734, which expires in October 2012.

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Corlu (License 4126). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 4126, which covers approximately 75,000 gross acres. As of March 1, 2012, we had two producing wells on the Corlu exploration license. We plan to drill one well on the Corlu exploration license during 2012. We are the operator of License 4126, which expires in December 2013.

Velimese and Cayirdere (Licenses 3791 and 3792). We own a 50% working interest in Licenses 3791 and 3792, which cover an aggregate of approximately 125,000 gross acres. As of March 1, 2012, we had three producing wells on the Cayirdere exploration license. We plan to drill approximately six exploratory wells on License 3792 during 2012. TPAO is the operator of Licenses 3791 and 3792, which expire in August 2013 and October 2013, respectively.

Southeastern Turkey. The following is a map showing our interests in southeastern Turkey:

Selmo (Production Lease 829). We own a 100% working interest in Production Lease 829, which covers approximately 8,886 acres and includes the Selmo oil field. As of March 1, 2012, there were 57 producing wells on the Selmo production lease. For 2011, our net production of oil in the Selmo field was approximately 838,615 Bbls of oil, at an average rate of approximately 2,298 Bbls per day. We plan to drill approximately 15 wells on the Selmo production lease during 2012. We are the operator of Production Lease 829, which expires in June 2015. We plan to submit an application to extend the expiration date of Production Lease 829 to June 2025.

Arpatepe (Production Lease 3118-5003 and License 5025). We own a 50% working interest in Production Lease 3118-5003 and License 5025, which cover approximately 11,200 and 84,600 gross acres, respectively. For 2011, our net production of oil from the Arpatepe field was approximately 49,994 Bbls of oil, at an average rate of approximately 137 Bbls per day. As of March 1, 2012, we had three producing wells on the Arpatepe production lease, and we plan to drill approximately three wells there during 2012. Aladdin Middle East, Ltd. (Aladdin) is the operator of Production Lease 3118-5003 and License 5025, which expire in November 2028 and February 2016, respectively.

Bakuk and Idil (Licenses 4069 and 4642). We own a 50% working interest in Licenses 4069 and 4642. The licenses cover an aggregate of approximately 219,000 gross acres on the Turkish border with Syria. We have completed construction of a 23-kilometer, 6-inch pipeline from the Bakuk-101 exploration well to an existing pipeline to the south and began selling limited quantities of natural gas in the second quarter of 2011. TPAO completed a tie-in from our pipeline to a nearby power plant, and we expect natural gas sales to the power plant to begin in 2012. We plan to drill approximately three wells on License 4069 and one well on License 4642 during 2012. Tiway Turkey, Ltd. (Tiway) is the operator of License 4069, which expires in September 2013. Tiway has applied for a production lease on License 4069, and if a production lease is granted, we and Tiway plan to apply for an exploration license covering the remaining original acreage in License 4069. We are the operator of License 4642, which expires in October 2014.

Molla (Licenses 4174 and 4845). We own a 100% working interest in Licenses 4174 and 4845, which cover an aggregate of approximately 50,000 acres adjacent to the northern border of our former License 3118 (now Production Lease 3118-5003). Our primary target is an underexplored Paleozoic play at a depth of approximately 9,800 feet. In 2011, we completed the Goksu-1 well as a new field discovery in the Mardin formation. In December 2011, we drilled the successful Goksu-2 appraisal well, and we plan to drill the Goksu-3 well on License 4845 in the second quarter of 2012. We believe this well will be the first horizontal well to test the fractured Mardin carbonate formations found in this region. We are the operator of Licenses 4174 and 4845, which expire in June 2012 and March 2014, respectively. We have applied for a two-year extension of the term of License 4174. We have also applied for an approximately 62,000 acre license immediately offsetting these licenses.

Central Basins. Our exploration licenses in central Turkey cover largely unexplored tertiary basins. We are currently seeking partners for these exploration licenses. Through farm-outs, we expect to reduce our exploration risk and accelerate the exploration and development activities on the farmed out properties. We intend to remain as operator of the properties that we farm-out. The following is a map showing our interests in central Turkey:

Adana/Yuksekkoy (Licenses 4350 and 4842). We own a 100% working interest in Licenses 4350 and 4842, which cover an aggregate of approximately 242,000 acres in the Adana area of southern Turkey. We plan to drill one exploratory well on License 4350 in 2012. We are the operator of Licenses 4350 and 4842, which expire in March 2014 and June 2015, respectively.

Malatya (Licenses 4659 and 4660). We own a 100% working interest in Licenses 4659 and 4660, which cover an aggregate of approximately 228,000 acres in the Malatya area of south-central Turkey. We paid a third party who will be a 10% working interest owner in the Malatya licenses cash consideration and agreed that the party would back-in for its 10% working interest after payout of the first well to be drilled on the Malatya licenses. These licenses are in a large, relatively unexplored tertiary basin. We are the operator of Licenses 4659 and 4660, which expire in January 2014.

Tuz Golu South (Licenses 4717, 4718, 4719, 4720, 4721 and 4722). We own a 100% working interest in Licenses 4717, 4718, 4719, 4720, 4721 and 4722, which cover an aggregate of approximately 733,000 acres in central Turkey. These licenses are in a large, relatively unexplored tertiary basin. We are the operator of the licenses, which expire in December 2014.

Sivas Basin (Licenses 4729, 4730, 4731, 4732, 4733, 4734, 4735, 4736, 4737, 4738, 4739, 4740 and 4741). We own a 100% working interest in Licenses 4729, 4730, 4731, 4732, 4733, 4734, 4735, 4736, 4737, 4738, 4739, 4740 and 4741, which cover an aggregate of approximately 1.6 million acres in central Turkey. These licenses are in a large, relatively unexplored tertiary basin. In February 2012, we entered into an agreement with Shell to farm-out a 60% working interest in the licenses. We are the operator of the licenses, which expire in December 2014.

Gurun (License 4325). We own a 90% working interest in License 4325, which covers approximately 122,000 gross acres in central Turkey. In April 2009, we farmed-in for a 90% interest in License 4325 for cash consideration and the obligation to carry a 10% interest in the first well drilled. We plan to drill one well on License 4325 in 2012. We are the operator of License 4325, which expires in February 2014.

Gaziantep (Licenses 4607, 4648, 4649 and 4656). We own a 62.5% working interest in Licenses 4607, 4648, 4649 and 4656 (subject to a farm-in obligation of TEMI to earn a 50% working interest, and further subject to a 0.625% overriding royalty interest), which cover an aggregate of approximately 488,000 gross acres near the Turkish border with Syria. We are the operator of these licenses, which expire in October 2013, except for License 4607, which expires in August 2013.

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Bulgaria

General. As of March 1, 2012, we held interests in two onshore exploration permits 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 bans the fracture stimulation of oil and natural gas wells in Bulgaria. As long as this legislation remains in effect, our exploration, development and production activities in Bulgaria will be significantly constrained. The following is a map showing our interests in Bulgaria and Romania:

Reserves. As of December 31, 2011, we had total net proved reserves of 378 Mmcf of natural gas, net probable reserves of 46 Mmcf of natural gas and net possible reserves of 53 Mmcf of natural gas 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.

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 19% 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 Leva (approximately $21 at March 1, 2012) per square kilometer, or 45 Bulgarian Leva (approximately $31 at March 1, 2012) 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 and Stefenetz. We have submitted an application for a production concession covering approximately 160,000 acres over the northern portion of our former A-Lovech exploration permit, which expired in November 2011. The Koynare Concession Area contains the Deventci-R1 well, where we discovered a reservoir in the Jurassic-aged Orzirovo formation at a depth of approximately 13,800 feet, which the Bulgarian government has certified as a geologic discovery. As of March 1, 2012, the well was producing approximately 250 Mcf/d of natural gas on a limited test basis, which is sold to a compressed natural gas facility adjacent to the Deventci-R1 well. In November 2011, we commenced drilling an appraisal well, the Deventci-R2, on the Koynare Concession Area.

We have also submitted an application 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. 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. We collected more than 900 feet of core, which is currently under evaluation. If the well is successful and 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.

In January 2012, the Bulgarian Parliament enacted legislation that bans fracture stimulation in the Republic of Bulgaria. The legislation also restricts the injection of fluids into underground formations at pressures greater than approximately 300 pounds per square inch. As a result, we have temporarily suspended drilling and completion operations for the Deventci-R2 and Peshtene-R11 wells. Although we expect the Bulgarian government to clarify the legislation to allow for conventional drilling and to institute a set of procedures regulating the fracture stimulation of wells, we cannot be certain when or if this will occur. In the meantime, we and LNG are evaluating the core data and developing a conventional completion program for the Peshtene-R11 well.

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 expires in April 2012. Due to the fracture stimulation ban, we have applied for a force majeure extension of this permit.

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Romania

General. As of March 1, 2012, we owned an interest in one onshore production license in Romania, which was acquired through a farm-in agreement with Sterling in June 2009. As of December 31, 2011, there were no reserves associated with our Romanian properties. Please see Bulgaria General for the map showing our interest in Romania.

Commercial Terms. Romania 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, excise tax and income tax. Two forms of royalty are payable as:

- a percentage of the value of gross production on a field basis, such percentage being fixed on a sliding scale depending on production levels. The production royalty rate varies between 3.5% to 13.5% for oil and natural gas production; and

- a fixed percentage of the gross income obtained from the transportation and transit of petroleum through the national pipeline system and from petroleum operations carried out through oil terminals belonging to the state. The royalty rate is currently fixed at 10%.

The license holder pays Romanian corporate income tax, but enjoys a one-year income tax holiday from the first day of production. Corporate income tax is assessed at a rate of 16%. All costs incurred in connection with exploration, development and production operations are deductible for corporate income tax purposes. Excise duty is payable on oil and natural gas at the rate of 4 Euro per ton of oil and between 0.32 Euro and 2.6 Euro per gigajoule of natural gas, depending on the end use of the natural gas. Excise tax is not payable on oil or natural gas delivered as royalty to the Romanian government or on quantities directly exported. Resident companies which remit dividends outside of Romania are subject to a dividend withholding tax at 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 for the conduct of petroleum operations. There is also a 24% 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 Ministry of Industry and Resources of Romania has responsibility for petroleum policy and strategy. The National Agency for Mineral Resources (NAMR) was set up in 1993 to administer and regulate petroleum operations. When licenses are to be made available, NAMR publishes a list of available blocks for concession in the Official Gazette. Foreign and Romanian companies must register their interest by a specified date and must submit applications by an application deadline. Applicants are required to prove their financial capacity, technical expertise and other requirements as required by NAMR. The licensing rounds are competitive and the winning bid is based on a scoring system.

NAMR negotiates the terms of agreements granting the licenses with the winning licensee and the license agreement is then submitted to the Romanian government for its approval. The date of government approval is the effective date of the license. Blocks which fail to attract a prescribed level of bids are re-offered in a subsequent licensing round. NAMR may issue a prospecting permit or a petroleum concession. A prospecting permit is for the conduct of geological mapping, magnetometry, gravimetry, seismology, geochemistry, remote sensing and drilling of wildcat wells in order to determine the general geological conditions favoring petroleum accumulations. A petroleum concession provides exclusive rights to conduct petroleum exploration and production under a petroleum agreement.

Sud Craiova. We own a 50% working interest in Sud Craiova Block E III-7, which covers approximately 1.0 million gross acres in western Romania. We and Sterling plan to shoot a 200 kilometer 2D seismic survey on the Sud Craiova license in 2012. Sterling is the operator of the Sud Craiova license, which expires in December 2013.

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Current Operations

During 2011, we continued to develop our Selmo oil field and our Thrace Basin natural gas properties. In addition, we continued the process of integrating the properties, equipment and personnel of Amity, Petrogas, Direct Bulgaria and TBNG into our operations. 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 evaluate opportunities for further activities in Bulgaria and Romania. For more information on our planned 2012 operations, see Item 1. Business Planned Operations.

Summary of Oil and Natural Gas Reserves

Substantially all of our net proved, probable and possible reserves are located in Turkey. The following table summarizes our net proved, probable and possible reserves at December 31, 2011 in accordance with the rules and regulations of the SEC.

		Reserves	
Reserves Category	**Oil and Condensate (Mbbl)**	**Natural Gas (Mmcf)**	**Total (Mboe)**
Proved Reserves			
Proved Developed	5,373	10,520	7,126
Proved Undeveloped	5,842	2,703	6,293
Probable Reserves	4,801	12,668	6,912
Possible Reserves	11,656	105,226	29,194
Total	27,672	131,117	49,525

Value of Proved Reserves

The following table shows our estimated future net revenue, PV-10 and Standardized Measure as of December 31, 2011:

(in thousands)	
Future net revenue	$ 996,473
Total PV-10(1)	$ 645,837
Total Standardized Measure	$ 531,797

(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:

(in thousands)	
Total PV-10	$ 645,837
Future income taxes	(171,592)
Discount of future income taxes at 10% per annum	57,552

Standardized Measure	$ 531,797

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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, 2011, our estimated proved reserves were 13,419 Mboe, a decrease of 19.5% compared to 16,673 Mboe at December 31, 2010. During 2011, we added estimated proved reserves of 111 Mboe through extensions and discoveries driven by our 2011 drilling activity in Turkey. In addition, we added estimated proved reserves of 938 Mboe through the acquisition of TBNG. These increases were offset by production volumes of approximately 1,667 Mboe and performance revisions in existing producing wells.

Proved Undeveloped Reserves

At December 31, 2011, our estimated proved undeveloped reserves were 6,293 Mboe, a decrease of 24.4% compared to 8,326 Mboe at December 31, 2010. This decrease in proved undeveloped reserves was primarily attributable to 966 Mboe of proved undeveloped reserves being converted to proved developed reserves in Selmo and a reduction of proved undeveloped reserves in Alpullu and Edirne of 954 Mboe due to proved undeveloped reserves being converted to proved developed reserves and performance revisions in existing producing wells. The 966 Mboe of proved undeveloped reserves that were converted to proved developed reserves was due to drilling and completing eight proved undeveloped well locations. During 2011, we incurred $13.1 million in capital expenditures to drill and complete these eight proved undeveloped wells. At December 31, 2011, no material amounts of proved undeveloped reserves remained undeveloped for five years or more after they were initially disclosed as proved undeveloped reserves. We intend to convert the proved undeveloped reserves disclosed as of December 31, 2011 to proved developed reserves within five years of the date they were initially disclosed as proved undeveloped reserves.

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, 2011, our estimated probable reserves were 6,912 Mboe, a decrease of 41.1% compared to 11,726 Mboe at December 31, 2010. This decrease in probable reserves was primarily attributable to 7,985 Mboe of probable reserves that were removed due to poor drilling results, performance revisions in existing wells and changes in development plans. The decrease in probable reserves was partially offset by an increase in probable reserves during 2011 of 3,171 Mboe that was primarily attributable to the acquisition of TBNG in June 2011 and the addition of probable reserves in the Arpatepe field.

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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.

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, 2011, our estimated possible reserves were 29,194 Mboe, a decrease of 30.2% compared to 41,824 Mboe at December 31, 2010. This decrease in possible reserves was primarily attributable to 15,769 Mboe of possible reserves that were removed due to poor drilling results, performance revisions in existing wells and changes in development plans. The decrease in possible reserves was partially offset by an increase in possible reserves during 2011 of 3,139 Mboe that was primarily attributable to the acquisition of TBNG in June 2011 and an increase in possible reserves in the Pancarkoy prospect.

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. Our internal audit department has tested the processes and controls regarding our reserves estimates for 2011. Senior management reviews and approves our reserve 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, 2011 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 29 years of experience in oil and natural gas reservoir studies and evaluations, is a member of the Society of Petroleum Engineers and is a Registered Professional Engineer in the State of Texas. 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 internal senior reservoir engineer is the technical person primarily responsible for overseeing the reserve estimation process. He has a Bachelor of Science degree in Petroleum Engineering from the Middle East Technical University and a Masters Degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals. He has over 25 years of experience in the oil and natural gas industry, including experience in production and reservoir engineering, and is a member of multiple professional organizations.

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 Note 22 Supplemental oil and natural gas reserves and standardized measure 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, 2011 included a detailed review of our Selmo, Arpatepe, Bakuk, Molla and Thrace Basin properties in Turkey and our property 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 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, 2011, 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.

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Oil and Natural Gas Production

The following table sets forth our net production of oil and natural gas for 2011, 2010 and 2009:

		Net Production[1]	
Year	Oil[2] (Bbls)	Natural Gas (Mcf)	Total (Boe)
2011			
Turkey	889,574[3]	4,610,537	1,657,997
Bulgaria	1,171	45,692	8,786
2010			
Turkey	689,823[3]	1,707,421	974,393
2009			
Turkey	417,071[3]		417,071

(1) Does not include nominal production from properties in other countries.
(2) Oil volumes include condensate (light oil) and medium crude oil.
(3) During 2011, 2010 and 2009, our net production of crude oil in the Selmo field was 838,615 Bbls, 631,149 Bbls and 411,964 Bbls, respectively.

Production Prices 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 2011, 2010 and 2009:

	2011	2010	2009
Turkey			
Average Sales Price			
Oil ($/Bbl)	$ 100.26	$ 80.01	$ 66.05
Natural Gas ($/Mcf)	$ 7.08	$ 7.63	
Unit Costs			
Production ($/Boe)	$ 10.22	$ 20.48	$ 23.53
Bulgaria			
Average Sales Price			
Oil ($/Bbl)	$ 108.05		
Natural Gas ($/Mcf)	$ 4.60		
Unit Costs			
Production ($/Boe)	$ 71.89		

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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 for 2011, 2010 and 2009:

	Development Wells		Exploratory Wells	
	Productive	**Dry**	**Productive**	**Dry**
Turkey				
2011	14.54	5.50	2.55	6.60
2010	13.75	4.20	2.50	2.50
2009	5.10			
Romania				
2011				
2010		2.00		1.00
2009		3.00		0.50
Bulgaria				
2011				
2010				
2009				

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, 2011:

	Oil		Natural Gas	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**
Turkey	50	47.3	231	105.2
Bulgaria			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.

Developed Acreage. The following table sets forth our total gross and net developed acreage as of December 31, 2011:

	Developed (Acres)	
	Gross(1)	**Net(2)**
Turkey	47,095	28,090

(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, 2011:

	Undeveloped (Acres)	
	Gross(1)	**Net(2)**
Turkey	6,182,864	5,281,388

Bulgaria	567,005	567,005
Romania	988,421	494,211
Total	7,738,290	6,342,604

(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.

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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) Gross[1]	Net[2]	% of Total Undeveloped (Acres) Net[2]
2012	1,560,823	1,219,946	19.2
2013	2,529,114	1,601,835	25.3
2014	2,928,961	2,801,431	44.2
2015	154,015	154,015	2.4
2016			

(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.

Item 3. Legal Proceedings

TEMI has been 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 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.

In 2003, a group of villagers living around the Selmo field 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 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 field lie within this enlarged area. In 2009, the Supreme Court overruled the Kozluk Civil Court of First Instance and directed that court to re-examine the case.

The Turkish Forestry Authority has 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 has 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 underlying litigation in the Kozluk Civil Court of First Instance.

In addition, TEMI is involved as a defendant in two nuisance cases in the Kozluk Cadastre Court and one claim for damages in the Kozluk Civil Court of First Instance. The plaintiffs in each of these cases are the same villagers in the underlying litigation. The Turkish Treasury Department and the Turkish Forestry Authority have joined TEMI as defendants in each of these nuisance cases. Each of the Kozluk Cadastre Court and the Kozluk Civil Court of First Instance has decided to suspend each of these nuisance cases until there is a resolution of the underlying litigation in the Kozluk Civil Court of First Instance.

We do not believe these cases have merit and intend to continue to vigorously defend our interests. The ultimate liability with respect to these claims cannot be determined at this time; however, we do not expect these matters to have a material impact on our financial position, operations or liquidity, and we have not taken a reserve for them.

Item 4. Mine Safety Disclosures

Not applicable.

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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.

	High	Low
2011:		
First Quarter	$ 3.49	$ 2.81
Second Quarter	$ 3.08	$ 1.51
Third Quarter	$ 1.67	$ 0.76
Fourth Quarter	$ 1.70	$ 0.69
2010:		
First Quarter	$ 3.80	$ 2.61
Second Quarter	$ 4.20	$ 3.03
Third Quarter	$ 3.61	$ 2.84
Fourth Quarter	$ 3.52	$ 3.00

United States

Our common shares are traded in the United States on the NYSE Amex 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 Amex for the periods indicated.

	High	Low
2011:		
First Quarter	$ 3.59	$ 2.81
Second Quarter	$ 3.18	$ 1.62
Third Quarter	$ 1.74	$ 0.75
Fourth Quarter	$ 1.67	$ 0.57
2010:		
First Quarter	$ 3.73	$ 2.43
Second Quarter	$ 4.10	$ 2.87
Third Quarter	$ 3.49	$ 2.68
Fourth Quarter	$ 3.50	$ 2.96

Common Shares and Dividends

As of March 1, 2012, we had 366,534,449 common shares issued and outstanding and held by approximately 318 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, 2006 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	2006	2007	2008	2009	2010	2011
TransAtlantic Petroleum Ltd.	$ 100	$ 32	$ 79	$ 394	$ 383	$ 151
Russell 2000 Index	$ 100	$ 98	$ 65	$ 83	$ 105	$ 101
S&P/TSX Capped Energy Sector Index	$ 100	$ 111	$ 68	$ 96	$ 108	$ 92

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 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.

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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, 2011. 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,				
	2011	2010	2009	2008	2007
	(amounts in thousands, except per share amounts)				
Total revenues	$ 126,338	$ 70,854	$ 27,748	$ 111	$ 653
Loss from continuing operations	75,220	31,495	40,061	16,475	6,318
Comprehensive loss	168,291	77,514	52,545	16,475	6,318
Basic and diluted net loss attributable to common shareholders, per common share, from continuing operations	0.21	0.10	0.19	0.25	0.15
Basic and diluted weighted average number of shares outstanding	355,971	312,488	212,320	66,524	43,047

	As of December 31,				
	2011	2010	2009	2008	2007
	(amounts in thousands)				
Total assets	$ 443,993	$ 473,968	$ 307,083	$ 81,254	$ 5,107
Long-term liabilities	112,869	62,486	13,341	14	8
Shareholders equity	176,204	276,057	264,607	74,940	2,070
Capital expenditures, including acquisitions	152,440	170,317	92,359	10,268	4,126

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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 are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty and tax rates to exploration and production companies. We hold interests in developed and undeveloped oil and natural gas properties in Turkey, Bulgaria and Romania. As of March 1, 2012, we held approximately 5.4 million net onshore acres. As of March 1, 2012, approximately 40% of our outstanding common shares were beneficially owned by N. Malone Mitchell, 3rd, the chairman of our board of directors and chief executive officer.

2011 Financial and Operational Performance

During 2011, we derived 79.2% of our oil and natural gas revenues from the production of oil and 20.8% of our oil and natural gas revenues from the production of natural gas.

Total oil and natural gas revenue increased to $124.2 million for 2011 from $69.8 million realized in 2010. The increase was primarily the result of increased production due to our acquisitions of Amity and Petrogas in August 2010, Direct Bulgaria in February 2011 and TBNG in June 2011. The increase was also due to an increase in the average price received, which was $74.50 per Boe during 2011, as compared to $71.63 per Boe for 2010.

Production increased to 891 net Mbbls of crude oil and 4,657 net Mmcf of natural gas for 2011, compared to 690 net Mbbls of crude oil and 1,709 net Mmcf of natural gas for 2010.

In 2011, we incurred $152.4 million in capital expenditures compared to capital expenditures of $170.3 million in 2010. The decrease is primarily due to lower acquisition costs in 2011.

During 2011, we decreased our short-term borrowings to $80.7 million, compared to short-term borrowings of $106.7 million in 2010.

Our net loss from continuing operations for 2011 was approximately $75.2 million, consisting primarily of the impairment of our oil and natural gas properties of approximately $44.7 million related to certain of our proved and unproved properties.

Recent Developments

We have completed a number of material acquisitions, financings and operations during 2011. For additional information on our recent developments, see Item 1. Business Recent Developments.

Current Operations

During 2011, we continued to develop our Selmo oil field and our Thrace Basin natural gas properties. In addition, we continued the process of integrating the properties, equipment and personnel of Amity, Petrogas, Direct Bulgaria and TBNG into our operations. 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 evaluate opportunities for further activities in Bulgaria and Romania. For more information on our planned 2012 operations, see Item 1. Business Planned Operations.

Discontinued Operations in Morocco

On June 27, 2011, we decided to discontinue our Moroccan operations. We are in the process of winding down our operations in Morocco. We have presented the Moroccan segment operating results as discontinued operations for all periods presented, and they are not included in results from continuing operations.

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Discontinued Operations of Oilfield Services Business

On September 30, 2011, we engaged a financial advisor to assist with the sale, transfer or other disposition of our oilfield services business. We have presented the oilfield services business segment operating results as discontinued operations for all periods presented.

On March 15, 2012, we signed a stock purchase agreement to sell Viking for an aggregate purchase price of $164.0 million, consisting of $152.5 million in cash, subject to a net working capital adjustment, and a $11.5 million promissory note from Dalea. The sale of Viking is subject to the approval of regulatory authorities, the receipt of equity financing by the buyer and other customary closing conditions. The closing is anticipated to occur during the second quarter of 2012. We intend to use approximately $4.0 million of the cash consideration to repay (i) the outstanding balance on our amended and restated note payable from Viking International to Viking Drilling and (ii) the outstanding balance of a secured credit agreement entered into by Viking International to fund the purchase of vehicles. In addition, we intend to use a portion of the remaining cash proceeds to repay our credit agreement with Dalea, and we may use the remaining cash proceeds along with existing cash to repay some or all of the outstanding indebtedness under our Amended and Restated Credit Facility.

Pursuant to the stock purchase agreement, the Company, Viking International and Viking Geophysical will enter into a five-year master services agreement that would provide us with continued access to Viking s equipment and services. After the consummation of the sale of these operations, we will no longer own drilling rigs and oilfield services equipment, which will increase our costs and expenses, but will reduce our depreciation and amortization expense and our general and administrative expense. We could also be subject to greater risks related to the availability and cost of drilling rigs and third party oilfield services.

There is no assurance that we will complete the sale of the oilfield services business as contemplated or at all.

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 3 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, 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 ASC 360, *Property, Plant and Equipment* (ASC 360). ASC 360 requires that our long-lived assets be assessed for potential impairment in their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. Oil and natural gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset 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 an independent expert. 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 estimated potential reserves and future net revenues from an independent expert, the Company s history in exploring the area, the Company s future drilling plans per its capital drilling program prepared by the Company s reservoir engineers and operations management and other factors associated with the area. Impairment is taken on the unproved property cost 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. Accordingly, transactions costs related to acquisitions are to be recorded as a reduction of earnings in the period they are incurred and costs related to issuing debt or equity securities that are related to the transaction will continue to be recognized in accordance with other applicable rules under U.S. GAAP. ASC 810-10-65 requires non-controlling interests to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for non-controlling interests and transactions with non-controlling interest holders in consolidated financial statements.

Foreign Currency Translation. 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 re-measuring transactions and monetary accounts in a currency other than the functional currency are included in earnings. For certain of our controlled entities, 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 balance sheet as a component of accumulated other comprehensive income (loss). The accounting basis of the assets and liabilities affected by the change are adjusted to reflect the difference between the exchange rate when the asset or liability arose and the exchange rate on the date of the change.

Other Recent Accounting Pronouncements and Reporting Rules

In January 2010, FASB issued Accounting Standards Update 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06). The update provides amendments to ASC 820, *Fair Value Measurements and Disclosures*, (ASC 820) that require more robust disclosures about: (1) the different classes

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of assets and liabilities measured at fair value, (2) the valuation techniques and inputs used, (3) the activity in Level 3 fair value measurements, and (4) the transfers between Levels 1, 2, and 3. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009. Disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The adoption of ASU 2010-06 did not have a material impact on our financial statements.

In December 2010, FASB issued ASU 2010-28, *Intangibles Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (ASU 2010-28). ASU 2010-28 modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The update is effective for interim and annual reporting periods beginning after December 15, 2010. This update is considered on an interim and annual basis when we review and perform our goodwill impairment test. The adoption of ASU 2010-28 did not have a material impact on our financial statements.

In December 2010, FASB issued ASU 2010-29, *Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29). ASU 2010-29 specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The update also expands the supplemental pro forma disclosures under ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The update is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The adoption of ASU 2010-29 did not have a material impact on our financial statements.

In May 2011, FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04). ASU 2011-04 amends ASC 820, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurement and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 will be effective for interim and annual periods beginning after December 15, 2011. The adoption of ASU 2011-04 is not expected to have a material effect on our financial statements, but may require certain additional disclosures.

In June 2011, FASB issued ASU 2011-05, *Presentation of Comprehensive Income* (ASU 2011-05). ASU 2011-05 requires the presentation of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. In December 2011, FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU 2011-05* (ASU 2011-12). ASU 2011-12 defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income. The amendments will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of ASU 2011-05 is not expected to have a material effect on our financial statements, but may require a change in the presentation of our comprehensive income from the notes of the financial statements, where it is currently disclosed, to the face of the financial statements.

In September 2011, FASB issued ASU 2011-08, *Intangibles Goodwill and Other (Topic 350): Testing Goodwill for Impairment* (ASU 2011-08). ASU 2011-08 allows both public and nonpublic entities an option to

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first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity would no longer be required to calculate the fair value of a reporting unit unless the entity determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. ASU 2011-08 allows early adoption and will be effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We are presently assessing the impact of ASU 2011-08.

In December 2011, FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210), Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11). ASU 2011-11 will require entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. Application of ASU 2011-11 is required for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. At that time we will make the necessary disclosures.

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.

Results of Operations Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

	Year Ended December 31, 2011	2010	Change 2011-2010
	(in thousands of U.S. dollars, except per unit prices and production volumes) (as adjusted)		
Production:			
Oil (Mbbl)	891	690	201
Natural gas (Mmcf)	4,657	1,709	2,948
Total production (Mboe)	1,667	975	692
Average prices:			
Oil (per Bbl)	$ 100.27	$ 80.01	$ 20.26
Natural gas (per Mcf)	$ 7.05	$ 7.63	$ (0.58)
Oil equivalent (per Boe)	$ 74.50	$ 71.63	$ 2.87
Revenues:			
Oil and natural gas sales	124,185	69,839	54,346
Other	2,153	1,015	1,138
Total revenues	126,338	70,854	55,484
Costs and expenses:			
Production	17,934	20,286	(2,352)
Exploration, abandonment and impairment	60,234	12,691	47,543
Seismic and other exploration	9,627	16,883	(7,256)
Contingent consideration and contingencies	6,000		6,000
General and administrative	35,388	26,049	9,339
Depreciation, depletion and amortization	41,655	16,436	25,219
Interest and other expense	13,464	7,055	6,409
Foreign exchange loss	11,730	1,872	9,858
Loss on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(4,854)	(29)	(4,825)
Non-cash change in fair value on commodity derivative contracts	(3,572)	(1,595)	(1,977)
Total loss on commodity derivative contracts	(8,426)	(1,624)	(6,802)

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Oil and Natural Gas Sales. Total oil and natural gas sales increased to $124.2 million in 2011, from $69.8 million in 2010. Of this increase, $4.8 million was the result of an increase in the average prices received and $49.6 million was the result of an increase in our production volumes of 692 Mboe to 1,667 Mboe for 2011, compared to 975 Mboe for the same period in 2010. Production volumes increased primarily due to the acquisitions of Amity and Petrogas in August 2010 and TBNG in June 2011, which accounted for approximately 629 Mboe of the increase. The remaining production volume increase was primarily attributable to increased production in the Selmo and Arpatepe oil fields. Our average price received for 2011 was $74.50 per Boe, compared to $71.63 per Boe for 2010.

Production. Production expenses for 2011 decreased to $17.9 million from $20.3 million in 2010. The decrease in production expenses was primarily attributable to the increase in the utilization of our own oilfield services business to provide these services. We would expect production expenses to increase in 2012, with the divestiture of our oilfield services business.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs increased to $60.2 million in 2011 compared to $12.7 million for 2010. The increase was primarily due to the impairment of our Bulgarian properties of $25.9 million following the ban on fracture stimulation enacted by the Bulgarian Parliament in January 2012. Additionally, we recorded impairments of approximately $18.8 million in Turkey. This was primarily driven by downward revisions in natural gas reserves in the Alpullu and Edirne fields.

Seismic and Other Exploration. Seismic and other exploration costs decreased to $9.6 million for 2011, compared to $16.9 million for 2010. The decrease was due primarily to our seismic programs in 2011 occurring on licenses that we jointly hold with other working interest owners who bore their proportionate share of the costs.

Contingent Consideration and Contingencies. 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 acquisition of Direct Morocco, Anschutz and Direct Bulgaria. Therefore, we have increased our costs and expenses by $6.0 million in 2011 to reflect our potential future costs.

General and Administrative. General and administrative expense was $35.4 million for 2011, compared to $26.0 million for 2010, primarily due to the overall expansion of our business in 2011, an increase in consulting and professional service fees, primarily related to the late filings 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 and for the evaluation of bond financing.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $41.7 million for 2011, compared to $16.4 million in 2010. The increase was due primarily to increased production, as well as an increase in our depletable base, both of which were primarily the result of recent acquisitions. The increase was also due to downward reserve revisions which increased the depletion rate for certain fields.

Interest and Other Expense. Interest and other expense increased to $13.5 million for 2011, as compared to $7.1 million for 2010. The increase was primarily due to an increase in our outstanding debt. At December 31, 2011, our total outstanding debt was approximately $163.8 million (of which $5.0 million was held for sale), compared to $136.8 million at December 31, 2010.

Foreign Exchange Loss. We recorded a foreign exchange loss of $11.7 million in 2011 compared to a loss of $1.9 million in 2010. The increase is primarily due to the devaluation of the New Turkish Lira (TRY) compared to the U.S. dollar in 2011.

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Loss on Commodity Derivative Contracts. During 2011, we recorded a loss of $8.4 million, as compared to a loss of $1.6 million for 2010. We recorded a $3.6 million unrealized loss and a $4.9 million realized loss on our derivative contracts for 2011, compared to a $1.6 million unrealized loss and a $29,000 realized loss for 2010. Unrealized gains and losses are attributable to changes in oil and natural gas prices and volumes hedged from one period end to another. 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 Arpatepe oil fields in Turkey.

Other Comprehensive Loss (Gain). We record foreign currency translation adjustments from the process of translating the functional currency of the financial statements of our foreign subsidiaries into the U.S. Dollar reporting currency. Foreign currency translation adjustment for 2011 increased to $52.4 million from $7.8 million for 2010 due to the devaluation of the TRY compared to the U.S. dollar in 2011.

Discontinued Operations. All revenues and expenses associated with our Moroccan operations and oilfield services business for 2011 and 2010 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,	
	2011	2010
	(in thousands)	
Revenues:		
Oil and natural gas sales	$ 217	$
Oilfield services	28,281	14,709
Total revenues	28,498	14,709
Costs and expenses:		
Production	928	
Exploration, abandonment and impairment	23,121	19,924
Seismic and other exploration	67	195
Oilfield services costs	24,157	18,899
General and administrative	9,366	3,681
Depreciation, depletion and amortization	9,204	10,025
Accretion	1	
Total costs and expenses	66,844	52,724
Operating loss	(38,346)	(38,015)
Other (expense) income:		
Interest and other expense	(675)	(1,786)
Interest and other income	103	86
Foreign exchange gain	3,090	2,683
Total other (expense) income	2,518	983
Loss before income taxes from discontinued operations	(35,828)	(37,032)
Current income tax expense	(4,518)	(89)
Deferred income tax expense	(277)	(1,130)
Net loss from discontinued operations	$ (40,623)	$ (38,251)

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Results of Operations Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

	Year Ended December 31, 2010	2009	Change 2010-2009
	(in thousands of U.S. dollars, except per unit prices and production volumes)		
		(as adjusted)	
Production:			
Oil (Mbbl)	690	418	272
Natural gas (Mmcf)	1,709	1	1,708
Total production (Mboe)	975	418	557
Average prices:			
Oil (per Bbl)	$ 80.01	$ 74.17	$ 5.84
Natural gas (per Mcf)	$ 7.63	$ 7.58	$ 0.05
Oil equivalent (per Boe)	$ 71.63	$ 66.22	$ 5.41
Revenues:			
Oil and natural gas sales	69,839	27,681	42,158
Other	1,015	67	948
Total revenues	70,854	27,748	43,106
Costs and expenses:			
Production	20,286	10,077	10,209
Exploration, abandonment and impairment	12,691	14,790	(2,099)
Seismic and other exploration	16,883	14,602	2,281
General and administrative	26,049	15,227	10,822
Depreciation, depletion and amortization	16,436	4,371	12,065
Interest and other expense	7,055	2,303	4,752
Loss on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(29)		(29)
Non-cash change in fair value on commodity derivative contracts	(1,595)	(1,922)	327
Total loss on commodity derivative contracts	(1,624)	(1,922)	298

Oil and Natural Gas Sales. Total oil and natural gas sales increased to $69.8 million in 2010, from $27.7 million realized in 2009. Of this increase, $36.9 million was the result of an increase in our production volumes from 557 Mboe to 975 Mboe, and $5.3 million was the result of an increase in average prices received in 2010. Our average price received for 2010 was $71.63 per Boe, compared to $66.22 per Boe for 2009. Production volumes increased primarily due to increased production of 168 Mboe from our Edirne licenses, which began production in April 2010. Production volumes also increased due to the acquisitions of Amity and Petrogas in August 2010, which accounted for approximately 116 Mboe of the increase.

Production. Production expenses for 2010 increased to $20.3 million from $10.1 million in 2009. The increase in production expenses was the result of the acquisition of Amity and Petrogas in the third quarter of 2010 and an overall increase in production.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs decreased to $12.7 million in 2010, compared to $14.8 million for 2009. The decrease was primarily due to additional dry hole costs in Turkey.

Seismic and Other Exploration. Seismic and other exploration expense increased to $16.9 million for 2010, compared to $14.6 million for 2009. The increase was due primarily to increased exploration activity in Turkey.

General and Administrative. General and administrative expense was $26.0 million for 2010, compared to $15.2 million for 2009, primarily due to the expansion of our operating activities during 2010. We also recorded $1.7 million in transaction expenses relating to the acquisition of Amity and Petrogas during 2010.

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Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $16.4 million for 2010, compared to $4.4 million in 2009. The increase was due primarily to oilfield services equipment put into service in 2010 and the acquisition of Amity and Petrogas.

Interest and Other Expense. Interest and other expense increased to $7.1 million for 2010, compared to $2.3 million for 2009. The increase was primarily due to an increase in our outstanding debt. At December 31, 2010, our total outstanding debt was approximately $136.8 million, compared to $16.6 million at December 31, 2009.

Loss on Commodity Derivative Contracts. During 2010, we recorded a loss on commodity derivative contracts of $1.6 million, as compared to a loss of $1.9 million for 2009. We recorded a $1.6 million unrealized loss and a $29,000 realized loss on our derivative contracts for 2010, as compared to a $1.9 million unrealized loss for 2009. Unrealized gains and losses are attributable to changes in oil and natural gas prices and volumes hedged from one period end to another. We are required under our Amended and Restated Credit Facility to hedge a portion of our oil production in the Selmo and Arpatepe oil fields in Turkey.

Other Comprehensive Loss (Gain). We record foreign currency translation adjustments from the process of translating the functional currency of the financial statements of our foreign subsidiaries into the U.S. Dollar reporting currency. Foreign currency translation adjustment for 2010 decreased to a $7.8 million loss from a $9.6 million gain for 2009 due to the strengthening of the U.S. Dollar compared to the foreign currencies of the other countries in which we operate.

Discontinued Operations. All revenues and expenses associated with our Moroccan operations and oilfield services business for 2010 and 2009 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, 2010	2009
	(in thousands)	
Revenues:		
Oil and natural gas sales	$	$
Oilfield services	14,709	1,521
Total revenues	14,709	1,521
Costs and expenses:		
Production		91
Exploration, abandonment and impairment	19,924	10,001
Seismic and other exploration	195	2,746
Oilfield services costs	18,899	5,539
General and administrative	3,681	902
Depreciation, depletion and amortization	10,025	3,571
Accretion		
Total costs and expenses	52,724	22,850
Operating loss	(38,015)	(21,329)
Other (expense) income:		
Interest and other expense	(1,786)	(445)
Interest and other income	86	41
Foreign exchange gain (loss)	2,683	(4)
Total other (expense) income	983	(408)
Loss before income taxes from discontinued operations	(37,032)	(21,737)
Current income tax expense	(89)	(8)
Deferred income tax expense	(1,130)	(211)

Net loss from discontinued operations	$ (38,251)	$ (21,956)

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Capital Expenditures

For 2011, we incurred $152.4 million in capital expenditures compared to capital expenditures of $170.3 million for 2010. The decrease in capital expenditures was primarily due to lower acquisition costs in 2011. In 2012, we expect our capital expenditures will be approximately $130.0 million. We expect capital expenditures during 2012 to consist of approximately $110.0 million of drilling and completion expense (over 90 gross wells), $15.0 million of seismic expense and $6.0 million on infrastructure expense. Approximately 65% of these anticipated expenditures will occur in the Thrace Basin in Turkey, devoted to developing conventional and unconventional natural gas production, building infrastructure and acquiring seismic data. Most of the remaining 35% of these anticipated expenditures will occur in southeastern Turkey, devoted to drilling developmental and exploratory oil wells at Selmo, Arpatepe and Molla. If cash on hand, borrowings from our Amended and Restated Credit Facility and cash flow from operations are not sufficient to fund our capital expenditures, then we will either curtail our discretionary capital expenditures or seek other funding sources. If we successfully complete the sale of our oilfield services business, we may use a portion of the net proceeds to pay down our Amended and Restated Credit Facility, thereby increasing our capacity to fund capital expenditures. Our projected 2012 capital expenditure budget is subject to change and could be reduced if we do not raise additional funds.

Liquidity and Capital Resources

Our primary sources of liquidity for 2011 were our cash and cash equivalents and borrowings under our various debt agreements. At December 31, 2011, we had cash and cash equivalents of $15.1 million, $80.7 million in short-term debt associated with our continuing operations, $3.7 million in short-term debt associated with our discontinued operations, $78.0 million in long-term debt associated with our continuing operations, $1.3 million in long-term debt associated with our discontinued operations and, excluding assets held for sale of $128.1 million and liabilities held for sale of $26.7 million, a working capital deficit of $61.2 million, compared to cash and cash equivalents of $34.7 million, $108.6 million in short-term debt, $30.1 million in long-term debt and working capital deficit of $60.2 million at December 31, 2010. Cash provided by operating activities during 2011 was $40.5 million, as compared to cash used in operating activities of $43.5 million in 2010, primarily as a result of a 78.3% increase in revenues caused by net production volumes and higher realized prices and better cash management.

As of December 31, 2011, the outstanding principal amount of our debt was $163.8 million, of which $5.0 million was classified as held for sale. Of our outstanding debt, $73.0 million is due under the Dalea credit agreement upon the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of Viking or (y) two business days after demand by Dalea. We forecast that we will need to consummate the sale of Viking or raise additional debt or equity financing to fund our repayment of the Dalea credit agreement and to fund our operations, including our planned exploration and development activities. On March 15, 2012, we entered into a stock purchase agreement to sell Viking and a $15.0 million credit facility with Dalea to provide us with additional liquidity for general corporate purposes. Should we be unable to consummate the sale of Viking, raise additional financing or extend the maturity date of the Dalea credit agreement, we will not have sufficient funds to continue operations beyond June 30, 2012. As a result of the recurring losses from operations and a working capital deficiency, there is substantial doubt regarding our ability to continue as a going concern. The continuing application of the going concern assumption is dependent upon our continuing ability to obtain the necessary financing to discharge our existing obligations, fund ongoing exploration, development and operations and ultimately achieve profitable operations. The inability to secure additional funding when and as needed could have a material adverse effect on our operations and financial condition.

In addition to cash, cash equivalents and cash flow from operations, at December 31, 2011, we had an Amended and Restated Credit Facility, a credit agreement with Dalea, a term note with Viking Drilling, an equipment loan with a Turkish bank and a credit agreement with a Turkish bank, each of which is discussed below. In addition, we entered into a credit facility with Dalea in March 2012, which is also discussed below.

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Amended and Restated Credit Facility. DMLP, TEMI, Talon Exploration, TAT, Amity and Petrogas are parties to the Amended and Restated Credit Facility. Each of the Borrowers are our wholly owned subsidiaries.

The Amended and Restated Credit Facility is guaranteed by TransAtlantic Petroleum Ltd. and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide.

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, 2011, the lenders had aggregate commitments of $120.0 million, with individual commitments of $60.0 million each. On the last day of each fiscal quarter commencing September 30, 2012 and at the maturity date, the lenders commitments are subject to reduction by 6.25% of their commitments existing on such commitment reduction date.

The borrowing base is re-determined semi-annually on April 1st and October 1st of each year prior to September 30, 2012, and quarterly on January 1st, April 1st, July 1st and October 1st of each year after September 30, 2012. Following our semi-annual borrowing base redetermination on October 1, 2011, our borrowing base is currently $81.4 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 uncancelled 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. The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.75% per annum of the unused and uncancelled 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) 1.65% per annum of the unused and uncancelled 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.

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 (vii) 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 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.

At December 31, 2011, the Borrowers had borrowed $78.0 million under the Amended and Restated Credit Facility, had availability of $3.4 million under the Amended and Restated Credit Facility and were in compliance with all material covenants 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 2012, 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.

Dalea Credit Agreement. We also have a credit agreement with Dalea. Pursuant to the Dalea credit agreement, as amended, the aggregate unpaid principal balance, together with all accrued but unpaid interest and other costs, expenses or charges payable under the Dalea credit agreement are due and payable by us upon the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of Viking or (y) two business days after demand by Dalea. The Dalea credit agreement is also subject to customary events of default, such as payment defaults, defaults in any terms, covenants or conditions of the agreement, the prohibition in trading in our common shares, suspension or delisting of our common shares from any stock exchange, the occurrence of a material adverse change and the occurrence of a change in control. If an event of default occurs and is continuing, Dalea may demand immediate payment of all monies owing under the Dalea credit agreement; provided, that with respect to certain specified events of default, all monies due under the Dalea credit agreement shall automatically become due and payable without any demand or any other action by Dalea or any other person.

Amounts due under the credit agreement accrue interest at a rate of three-month LIBOR plus 5.50% per annum beginning on May 1, 2011, to be adjusted monthly on the first day of each month. Prior to May 1, 2011, amounts due under the credit agreement accrued interest at a rate of three-month LIBOR plus 2.50% per annum. Interest on the Dalea credit agreement will cease to accrue from April 1, 2012 until the closing date of the sale of Viking. If the closing does not occur, the abated interest will be reinstated. In addition, we are required to pay all accrued interest in arrears on the last day of each month until the date of repayment and at any time that the principal balance is due and payable. We may prepay the amounts due under the credit agreement at any time before maturity without penalty.

The Dalea credit agreement is also subject to customary covenants, including covenants that limit our ability to, among other things, (i) make, give, create or permit or attempt to make, give or create any mortgage, charge, lien or encumbrance over any of our assets or any subsidiary s assets (subject to certain specified exceptions), (ii) change our name or jurisdiction of organization, (iii) declare or provide for any dividends or other similar payments, (iv) redeem or repurchase any of our shares, (v) make or permit the sale of, or disposition of, any substantial or material part of our business, assets or undertaking or that of any subsidiary, (vi) borrow or cause any subsidiary to borrow money from any person (subject to certain specified exceptions) without obtaining and delivering a duly signed assignment and postponement of claim by such person in form and terms satisfactory to Dalea, (vii) pay out or permit the payment of any shareholder loans or other indebtedness to non-arm s length parties by us or any subsidiary, or (viii) guarantee or permit the guarantee of the obligations of any other person by us or any subsidiary except in the ordinary course of business. In addition, any proceeds received by us or any subsidiary from any debt financings (subject to certain specified exceptions) must be used to repay amounts outstanding under the credit agreement, net of reasonable transaction and financing costs. We (or any subsidiary) are also required to repay amounts outstanding under the credit agreement from (i) any proceeds of any equity issuance received from Mr. Mitchell, his immediate family or any entities owned or controlled by Mr. Mitchell or his immediate family (collectively, the Mitchell Family), and (ii) all proceeds of any equity issuance in excess of $75.0 million (excluding any proceeds received from the Mitchell Family), net of reasonable transaction costs. Amounts repaid under the credit agreement cannot be reborrowed. We paid for Dalea s reasonable legal fees and other expenses incidental to the completion of the credit agreement.

Events of default under the Dalea credit agreement include, but are not limited to, payment defaults, defaults in the performance of any terms, covenants or conditions of the Dalea credit agreement or collateral documents, material misrepresentations by us or any subsidiary, we or any subsidiary ceases or threatens to cease to carry on business, the prohibition in trading in our shares or the suspension or delisting of our common shares from any stock exchange, any material adverse change occurs in us or any of our subsidiaries, Dalea believes in good faith that our ability to pay or perform any of the covenants contained in the Dalea credit agreement is materially impaired, our insolvency or the insolvency of any subsidiary, or a change in control of the Company. A change of control is defined as the change of ownership of, or control or direction over, directly or indirectly, 20% or more of our outstanding voting securities. If an event of default occurs and is continuing, Dalea may demand immediate payment of all monies owing under the Dalea credit agreement; provided, that with respect to certain specified events of default, all monies due under the Dalea credit agreement shall automatically become due and payable without any demand or any other action by Dalea or any other person.

Under the terms of the Dalea credit agreement, we were required to issue Dalea 100,000 common share purchase warrants for each $1.0 million in principal amount advanced under the credit agreement. We borrowed an aggregate of $73.0 million under the credit agreement, and on September 1, 2010, we issued 7,300,000 common share purchase warrants to Dalea. The common share purchase warrants are exercisable until September 1, 2013, and have an exercise price of $6.00 per share.

At December 31, 2011, we had borrowed $73.0 million under the Dalea credit agreement. No further borrowings are permitted under the Dalea credit agreement.

Viking Drilling Note. On July 27, 2009, Viking International purchased the I-13 drilling rig and associated equipment from Viking Drilling. Dalea owns 85% of Viking Drilling. Viking International paid $1.5 million in cash for the drilling rig and entered into a note payable with Viking Drilling in the amount of $5.9 million. On February 19, 2010, Viking International purchased the I-14 drilling rig and associated equipment from Viking Drilling and entered into an amended and restated note payable to Viking Drilling in the amount of $11.8 million, which was comprised of $5.9 million payable related to the I-14 drilling rig and $5.9 million payable related to the purchase of the I-13 drilling rig. Under the terms of the amended and restated note, interest is payable monthly at a floating rate of LIBOR plus 6.25%, and the amended and restated note is due and payable August 1, 2012. The amended and restated note is secured by the I-13 and I-14 drilling rigs and associated equipment. At December 31, 2011, the outstanding balance under this note was $2.9 million and the note is included in Liabilities held for sale related party in our Consolidated Balance Sheets.

Viking International Equipment Loan. In 2010, Viking International entered into a secured credit agreement with a Turkish bank to fund the purchase of vehicles. The credit agreement matures on July 20, 2014, bears interest at an annual rate of 3.84% and is secured by the vehicles purchased with the proceeds of the loan. There is no further availability under the credit agreement. At December 31, 2011, Viking International had an outstanding balance of $2.1 million under the secured credit agreement and the credit agreement is included in Liabilities held for sale in our Consolidated Balance Sheets.

TBNG Credit Agreement. TBNG is a party to an unsecured credit agreement with a Turkish bank. At December 31, 2011, there were outstanding borrowings of approximately 14.6 million New Turkish Lira (approximately $7.7 million) under the credit agreement. Borrowings under the credit agreement bear interest at a rate of 14.0% per annum, and interest is payable quarterly. The credit agreement matures on September 13, 2012, and may be renewed for an additional period on the same terms.

Dalea Credit Facility. On March 15, 2012, TransAtlantic Worldwide, TBNG and the Company (collectively, the Credit Facility Borrowers) entered into a $15.0 million credit facility with Dalea to provide us with additional liquidity for general corporate purposes until we complete the sale of Viking. If drawn, loans under the credit facility will accrue interest at a rate of three month LIBOR plus 5.5% per annum, to be adjusted monthly on the first day of each month. We will be required to pay all accrued interest in arrears on the last day of each month, and we may prepay outstanding amounts at any time before maturity without penalty. If drawn, any outstanding borrowings must be repaid upon the earlier of (i) July 1, 2012 or (ii) the sale of Viking.

The initial advance under the credit facility will be no less than $5.0 million, with subsequent advances to be in multiples of $1.0 million. For the initial advance, we will be required to pay Dalea an arrangement fee of $250,000. Under the credit facility, we will also be required to pay Dalea a commitment fee equal to 2.75% per annum of the difference between the $15.0 million committed amount and the outstanding balance measured and payable on the last day of each fiscal quarter.

Any proceeds received by us or any subsidiary from any debt financings (subject to certain specified exceptions) or from the sale of Viking, net of reasonable transaction and financing costs, must be used to repay amounts outstanding under the credit facility. In addition, the Dalea credit facility is subject to customary covenants, including covenants that limit the ability of the Credit Facility Borrowers to, among other things, (i) make, give, create or permit or attempt to make, give or create any mortgage, charge, lien or encumbrance over any assets of any Credit Facility Borrower or any subsidiary (subject to certain specific exceptions), (ii) change the name of any of the Credit Facility Borrowers or the jurisdictions of organization, (iii) declare or provide for any dividends or other payments or distributions (whether in cash, assets or indebtedness) based on share capital, (iv) redeem or purchase any of their shares, (v) make or permit any sale of or disposition of any substantial or material part of their business, assets or undertaking, or that of any subsidiary, (vi) save and (except for certain specified exceptions) borrow or cause or permit any subsidiary to borrow money from any other person, without first obtaining and delivering a duly signed assignment and postponement of claim by such person in form and terms satisfactory to Dalea, (vii) pay out or permit the payment out of any shareholders loans or other indebtedness to non-arm s length parties, or (viii) guarantee or permit the guarantee of the obligations of any other person, directly or indirectly, except in the ordinary course of business.

The Dalea credit facility is also subject to customary events of default, including payment defaults, defaults in observing or performing any term, covenant or condition of the Dalea credit facility or collateral documents, material misrepresentations by a Credit Facility Borrower or any subsidiary, a Credit Facility Borrower or any subsidiary ceases or threatens to cease to carry on business, the prohibition in trading in shares of any of the Credit Facility Borrowers or suspension or delisting from any stock exchange, a material adverse change in the financial condition of any of the Credit Facility Borrowers and any of their subsidiaries taken as a whole, Dalea believes in good faith and on commercially reasonable grounds that the ability of the Credit Facility Borrowers to pay or perform any of the covenants contained in the Dalea credit facility is materially impaired, insolvency of any of the Credit Facility Borrowers or any change of control of any of the Credit Facility Borrowers. Control is defined in the Dalea credit facility as ownership of or control or direction over, directly or indirectly, 20% or more of the outstanding voting securities of the Credit Facility Borrowers. If an event of default occurs and is continuing, Dalea may demand immediate payment of all monies owing under the Dalea credit facility; provided that with respect to certain specified events of default, all monies due under the Dalea credit facility shall automatically become due and payable without any demand or any other action by Dalea or any other person.

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Contractual Obligations

The following table presents a summary of our contractual obligations at December 31, 2011:

	Payments Due By Year (in thousands)						
	Total	2012	2013	2014	2015	2015	Thereafter
Debt	$ 163,778	$ 84,424	$ 794	$ 560	$	$	$ 78,000
Leases and other	15,579	4,819	2,513	1,763	1,234	835	4,415
Contracts	8,565	8,565					
Permits	13,000	13,000					
Total	$ 200,922	$ 110,808	$ 3,307	$ 2,323	$ 1,234	$ 835	$ 82,415

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements at December 31, 2011.

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 exposure in financial instruments follows. Our market risk sensitive instruments were entered into for hedging and investment purposes, not for trading purposes.

Interest Rate Risk

At December 31, 2011, our exposure to interest rate changes related primarily to borrowings under our Amended and Restated Credit Facility, credit agreement with Dalea and amended and restated note with Viking Drilling. We are subject to interest rate risks associated with interest rate fluctuations on these outstanding borrowings, as described under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Pursuant to our Amended and Restated Credit Facility, we are subject to interest rate risks associated with interest rate fluctuations on outstanding floating rate borrowings. At December 31, 2011, we had $78.0 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 (6.03% at December 31, 2011).

Pursuant to our credit agreement with Dalea, we are subject to interest rate risks associated with interest rate fluctuations on outstanding floating rate borrowings. At December 31, 2011, we had $73.0 million in outstanding borrowings under the Dalea credit agreement. The interest we pay on borrowings under this credit agreement is equal to three-month LIBOR plus 5.50% per annum (6.03% at December 31, 2011).

Pursuant to our amended and restated note with Viking Drilling, we are subject to interest rate risks associated with interest rate fluctuations on outstanding floating rate borrowings. At December 31, 2011, we had $2.9 million in outstanding borrowings under this promissory note. The interest we pay on borrowings under this note is equal to LIBOR plus 6.25% per annum (6.48% at December 31, 2011).

At December 31, 2011, we had approximately $153.9 million in outstanding floating rate borrowings. A hypothetical 10% change in the interest rates we pay on our outstanding floating rate borrowings as of December 31, 2011 would result in an increase or decrease in our interest costs of approximately $1.0 million per year.

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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 corporate entities in Turkey, Bulgaria and Romania is the local currency. The functional currency for TransAtlantic Petroleum Ltd. is the U.S. dollar. As a result, translation adjustments will result from the process of translating the functional currency of our subsidiary financial statements into the U.S. dollar reporting currency. Our currency exposures primarily relate to the New Turkish Lira, as our largest subsidiaries measure their assets, liabilities and results of operations using the New Turkish Lira. Such translation adjustments accumulate on our Consolidated Balance Sheets as a component of accumulated other comprehensive income (loss) and are recorded in our Consolidated Statements of Operations and Comprehensive Loss as foreign currency translation adjustments. As of December 31, 2011 and December 31, 2010, we had a $50.6 million loss and a $1.8 million gain, respectively, in accumulated other comprehensive income (loss) as a result of translation adjustments. For the years ended December 31, 2011 and 2010, we recorded losses of $52.4 million and of $7.8 million, respectively, of foreign currency translation adjustments.

We are also subject to foreign currency exposures as a result of our operations in the other foreign countries in which we operate and foreign currency fluctuations as oil prices received are referenced in U.S. dollar-denominated prices. We record foreign exchange (gain) loss on our Consolidated Statements of Operations and Comprehensive Loss as a component of other expense (income) for gains and losses which result from re-measuring transactions and monetary accounts into the functional currency in earnings. For 2011 and 2010, we recorded a foreign exchange loss of $11.7 million and a foreign exchange loss of $1.9 million, respectively. As of December 31, 2011, we had 19.0 million New Turkish Lira (approximately $10.0 million) in cash and cash equivalents that are remeasured into the functional currency using the period-end exchange rate, with such re-measurement gains or losses recorded in foreign exchange (gain) loss. We estimate that a 10% change in the exchange rates would impact such cash balances and our net loss by approximately $1.0 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. In December 2009, TEMI entered into costless derivative contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2011 and 2012. In April 2010, TEMI entered into three-way collar contracts and additional costless derivative contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2011 and 2012. In May 2011, TEMI entered into additional three-way collar contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2011, 2012 and 2013. In August 2011, TEMI entered into additional three-way collar contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2011 and 2012. In November 2011, TEMI entered into additional three-way collar contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2012, 2013, 2014 and 2015. 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.

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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. Our commodity derivative contracts are carried at their fair value in earnings as they occur. We recognize unrealized and realized gains and losses related to these contracts on a mark-to-market basis in our Consolidated Statements of Operations and Comprehensive 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. 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 the year ended December 31, 2011, we recorded a net unrealized loss on commodity derivative contracts of $3.6 million. We recorded a net unrealized loss on commodity derivative contracts of $1.6 million in 2010.

The following tables summarize our outstanding derivatives contracts with respect to future crude oil production as of December 31, 2011:

Type	Period		Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (Liability) (in thousands)
Collar	January 1, 2012	December 31, 2012	960	$ 64.69	$ 106.98	$ (2,529)
Collar	January 1, 2013	December 31, 2013	400	$ 75.00	$ 125.50	(116)
Collar	January 1, 2014	December 31, 2014	380	$ 75.00	$ 124.25	12
						$ (2,633)

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Type	Period		Quantity (Bbl/day)	Collars Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Additional Call Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (Liability) (in thousands)
Three-way collar contract	January 1, 2012	December 31, 2012	240	$ 70.00	$ 100.00	$ 129.50	$ (764)
Three-way collar contract	January 1, 2012	March 31, 2012	350	$ 85.00	$ 118.88	$ 138.13	$ (7)
Three-way collar contract	April 1, 2012	June 30, 2012	350	$ 85.00	$ 116.25	$ 137.38	$ (35)
Three-way collar contract	July 1, 2012	December 31, 2012	205	$ 85.00	$ 97.13	$ 162.13	$ (381)
Three-way collar contract	January 1, 2013	December 31, 2013	831	$ 85.00	$ 97.13	$ 162.13	$ (1,985)
Three-way collar contract	January 1, 2014	December 31, 2014	726	$ 85.00	$ 97.13	$ 162.13	$ (626)
Three-way collar contract	January 1, 2015	December 31, 2015	1,016	$ 85.00	$ 91.88	$ 151.88	$ (640)
							$ (4,438)

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

Not applicable.

Item 9A. Controls and Procedures

Acquisition of Direct and TBNG

In February 2011, we acquired Direct Bulgaria, Direct Morocco and Anschutz. In June 2011, we acquired TBNG. For purposes of determining the effectiveness of our disclosure controls and procedures and internal control over financial reporting as of December 31, 2011, management has excluded the internal control over financial reporting of Direct Bulgaria, Direct Morocco, Anschutz and TBNG from its evaluation of these matters. The acquired businesses represent approximately 15.9% of our consolidated total assets at December 31, 2011 and approximately 36.2% of our consolidated net loss for the year ended December 31, 2011.

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 the chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2011, 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, which excluded the internal control over financial reporting of Direct Bulgaria, Direct Morocco, Anschutz and TBNG, and as a result of the material weaknesses in internal control over financial reporting described below, our chief executive officer and chief financial officer concluded that, as of December 31, 2011, our disclosure controls and procedures were not effective.

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 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* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO). Based on its evaluation, which excluded the internal control over financial reporting of Direct Bulgaria, Direct Morocco, Anschutz and TBNG, our management concluded that our internal control over financial reporting was not effective as of December 31, 2011 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 did not maintain an effective period-end financial statement closing process. Specifically, the accounting complexity associated with an integrated oilfield services business and the lack of effective and efficient accounting processes of our foreign operations, resulted in delays in the divisional and corporate closing process which limited the ability of division and corporate office management to perform quality reviews on a timely basis. This has resulted in certain account balances, reconciliations and journal entries lacking the appropriate validation. Because of this deficiency, which is pervasive in nature, we recorded post-closing adjustments to our 2011 consolidated financial statements and there is a reasonable possibility that a material misstatement of our financial statements will not be prevented or detected on a timely basis.

- we did not maintain effective controls over the translation of our foreign entity account balances. Specifically, effective controls were not in place to ensure that foreign exchange gains and losses were appropriately calculated and recorded in our reporting currency financials. Because of this deficiency, which is pervasive in nature, we recorded post-closing adjustments to our 2011 consolidated financial statements and there is a reasonable possibility that a material misstatement of our financial statements will not be prevented or detected on a timely basis.

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Management s Plan for Remediation of Our Material Weaknesses

Management s plan to remediate our material weaknesses and to strengthen our internal control over financial reporting by December 31, 2012 is to continue addressing the inefficiencies in our processes which contributed to the material weaknesses. We expect that the sale of our oilfield services business would simplify our accounting processes. We plan to reduce our chart of accounts, 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 Dallas, Texas offices. Our focus will be to continue improving the processes and controls over account reconciliations and journal entries. Additionally, we will evaluate whether new accounting software might be available to help automate some of the manual calculations we currently make in our financial closing process, thereby reducing the time required to prepare the calculations and mitigating the risks inherent in manual processes. Our chief executive officer and chief financial officer will 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.

As previously disclosed under Item 9A Controls and Procedures in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010, management concluded that our internal control over financial reporting was not effective based on the material weaknesses identified. Management worked throughout the year to remediate the material weaknesses that existed as of December 31, 2010. In the quarter ended December 31, 2011, management had sufficient evidence to conclude that remediation was completed for a number of material weaknesses that were previously reported. The significant changes in internal control over financial reporting that resulted in the remediation of the material weaknesses were as follows:

- we formed a new accounting management team that was tasked with achieving and maintaining a strong control environment, high ethical standards and financial reporting integrity. During 2011, we created the new accounting management team by taking the following actions:
  - our board of directors appointed Mr. Mitchell as our chief executive officer in May 2011;
  - we hired U.S. GAAP-experienced accounting management personnel (including a director of internal audit, a corporate controller and director of financial reporting, an exploration and production controller, an oilfield services controller and a director of mergers and acquisitions accounting) in June 2011;
  - our board of directors appointed Mr. Saqueton as our chief financial officer in August 2011; and
  - we hired a director of finance and accounting with U.S. GAAP experience based in our Istanbul, Turkey office in October 2011;
- we integrated our accounting systems to a single accounting system located in our Istanbul, Turkey office to enhance the consolidation of our holding companies and our operating subsidiaries financial statements;
- we documented our accounting and disclosure policies and procedures, implemented training and increased supervision regarding the preparation and approval of account reconciliations, journal entries and financial statements;
- we hired an information technology director in our Istanbul, Turkey office to oversee daily operations and remediation of our accounting system;

we evaluated and enhanced our anti-fraud hotline program and improved internal communication and awareness with employees regarding ethics and the availability of the hotline; and

we created a disclosure committee in the third quarter of 2011 as part of our disclosure control process.

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Changes in Internal Control Over Financial Reporting

The following change in our internal control over financial reporting occurred during the fourth quarter of 2011 and has affected or is reasonably likely to materially affect, our internal control over financial reporting.

we hired a director of finance and accounting with U.S. GAAP experience based in our Istanbul, Turkey office in October 2011.

On August 25, 2010, we acquired Amity and Petrogas. We have integrated Amity s and Petrogas internal control over financial reporting, and management s evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2011 included an assessment of the internal control over financial reporting of Amity and Petrogas. We did not have any material changes to our internal controls due to the acquisition of Amity and Petrogas.

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.

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.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of the Report.

1. Reports of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2011 and 2010

Consolidated Statements of Operations and Comprehensive Loss for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Equity for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

2. Exhibits required to be filed by Item 601 of Regulation S-K

EXHIBIT INDEX

2.1	Purchase Agreement, dated January 28, 2011, by and between Direct Petroleum Exploration, Inc., TransAtlantic Worldwide, Ltd. and TransAtlantic Petroleum Ltd. (incorporated by reference to the Company s Current Report on Form 8-K dated January 28, 2011, filed with the SEC on February 3, 2011).
2.2	Share Purchase Agreement, dated April 23, 2011, by and between Mustafa Mehmet Corporation and TransAtlantic Worldwide, Ltd. (incorporated by reference to Exhibit 2.1 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on August 9, 2011).
2.3	First Amendment to Share Purchase Agreement, dated June 6, 2011, by and between Mustafa Mehmet Corporation and TransAtlantic Worldwide, Ltd. (incorporated by reference to Exhibit 2.2 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on August 9, 2011).
2.4	Multi-Party Agreement, dated June 6, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd., Valeura Energy, Inc., Valeura Energy (Netherlands) Coöperatief UA, Pinnacle Turkey Holding Company, LLC, Thrace Basin Natural Gas Turkiye Corporation, Pinnacle Turkey, Inc. and Corporate Resources B.V. (incorporated by reference to Exhibit 2.3 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on August 9, 2011).
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	Memorandum of Continuance of TransAtlantic Petroleum Ltd., dated August 20, 2009 (incorporated by reference to Exhibit 3.2 to the Company s Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
3.3	Bye-Laws of TransAtlantic Petroleum Ltd., dated July 14, 2009 (incorporated by reference to Exhibit 3.3 to the Company s Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
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).

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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).
4.4	Common Share Purchase Warrant, dated September 1, 2010, by and between TransAtlantic Petroleum Ltd. and Dalea Partners, LP (uncorporated by reference to Exhibit 4.4 to the Company s Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
4.5	Form of Common Share Certificate (incorporated by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-3, filed with the SEC on June 9, 2010).
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	Agreement for Management Services, dated December 15, 2009, by and between Viking International Limited and Viking Drilling, LLC (incorporated by reference to Exhibit 10.3 to the Company s Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
10.4	Amendment to Management Service Agreement, dated August 5, 2010, by and between Viking International Limited and Viking Drilling, LLC (incorporated by reference to Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on November 15, 2010).
10.5	Management Services Agreement, dated August 5, 2010, by and between Viking International Limited and Maritas A.S. (incorporated by reference to Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on November 15, 2010).
10.6	Agreement for Management Services, dated September 28, 2010, by and between Viking International Limited and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated September 28, 2010, filed with the SEC on September 28, 2010).
10.7	Credit Agreement, dated as of June 28, 2010, by and between TransAtlantic Petroleum Ltd. and Dalea Partners, LP (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated June 28, 2010, filed with the SEC on July 1, 2010).
10.8	Amended and Restated Note, dated February 19, 2010, by and between Viking International Limited and Viking Drilling, LLC (incorporated by reference to Exhibit 10.12 to the Company s Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
10.9	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).
10.10	Amended and Restated Stock Option Plan (2006) (incorporated by reference to Exhibit 4.4 to the Company s Registration Statement on Form 20-F (File No. 000-31643), filed with the SEC on October 9, 2007).

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10.11	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).
10.12	Form of Common Share Purchase Warrant, dated April 2, 2009, by and between TransAtlantic Petroleum Corp. and holders of options to purchase shares of Incremental Petroleum Limited (incorporated by reference to Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 27, 2009).
10.13	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).
10.14	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).
10.15	Form of Share Option Agreement (incorporated by reference to Exhibit 99.3 to the Company s Registration Statement on Form S-8, filed with the SEC on November 2, 2009).
10.16	Amendment to Credit Agreement, dated as of April 1, 2011, by and among TransAtlantic Worldwide, Ltd., as borrower, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., Amity Oil International Pty Limited and Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş., as guarantors, the lenders as defined in the Credit Agreement, and Standard Bank Plc, as administrative agent and collateral agent (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K dated April 1, 2011, filed with the SEC on April 6, 2011).
10.17	Amended and Restated Credit Agreement, dated as of May 18, 2011, by and between DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat 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).
10.18	First Amendment to Credit Agreement, dated May 18, 2011, by and between Dalea Partners, LP and TransAtlantic Petroleum Ltd. (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K dated May 17, 2011, filed with the SEC on May 19, 2011).
10.19	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 Inşaat 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).
10.20	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 Inşaat 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).

10.21	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).
10.22	Escrow Agreement, dated June 6, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd., Pinnacle Turkey Holding Company, LLC, Valeura Energy (Netherlands) Coöperatief UA, Mustafa Mehmet Corporation and American Escrow Company. (incorporated by reference to Exhibit 10.10 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on August 9, 2011).
10.23	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).
10.24	Letter Agreement, dated February 8, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.25	Amendment to Letter Agreement, dated March 18, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.26	Amendment to Letter Agreement, dated April 2, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.27	Amendment to Letter Agreement, dated April 15, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.28	Amendment to Letter Agreement, dated April 23, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.10 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.29	Amendment to Letter Agreement, dated April 29, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.11 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.30	Amendment to Letter Agreement, dated May 10, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.12 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.31	Amendment to Letter Agreement, dated May 19, 2011, by and between TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd. and Valeura Energy Inc. (incorporated by reference to Exhibit 10.13 to the Company s Quarterly Report on Form 10-Q, filed with the SEC on May 31, 2011).
10.32	Second Amendment to Credit Agreement, dated November 7, 2011, by and between Dalea Partners, LP and TransAtlantic Petroleum Ltd. (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K, dated November 7, 2011, filed with the SEC on November 14, 2011).

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21.1*	Subsidiaries of the Company.
23.1*	Consent of KPMG LLP.
23.2*	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 March 9, 2012.
101**	The following materials from the Company s Annual Report on Form 10-K for the year ended December 31, 2011, formatted in XBRL (eXtensible Business Reporting Language), (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Loss, (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to the Consolidated Financial Statements.

Management contract or compensatory plan arrangement.

* Filed herewith.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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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 23, 2012

TRANSATLANTIC PETROLEUM LTD.

/s/ N. Malone Mitchell, 3rd
N. Malone Mitchell, 3rd

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. Malone Mitchell, 3rd **N. Malone Mitchell, 3rd**	Chairman and Chief Executive Officer (Principal Executive Officer)	March 23, 2012
/s/ Wil F. Saqueton **Wil F. Saqueton**	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer/Controller)	March 23, 2012
/s/ Bob G. Alexander **Bob G. Alexander**	Director	March 23, 2012
/s/ Brian E. Bayley **Brian E. Bayley**	Director	March 23, 2012
/s/ Alan C. Moon **Alan C. Moon**	Director	March 23, 2012
/s/ Mel G. Riggs **Mel G. Riggs**	Director	March 23, 2012
/s/ Michael D. Winn **Michael D. Winn**	Director	March 23, 2012

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AND FINANCIAL STATEMENT SCHEDULES

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders

TransAtlantic Petroleum Ltd.

We have audited TransAtlantic Petroleum Ltd. s (the Company) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* 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 Report on Internal Control Over Financial Reporting* in Item 9A. 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 a company s annual or interim financial statements will not be prevented or detected on a timely basis. Material weaknesses relating to the Company not maintaining an effective period end financial statement closing process and effective controls over translation of its foreign entity account balances were identified and included in management s assessment.

TransAtlantic Petroleum Ltd. acquired Direct Petroleum Bulgaria EOOD (Direct Bulgaria), Direct Petroleum Morocco, Inc. (Direct Morocco), Anschutz Morocco Corporation (Anschutz) and Thrace Basin Natural Gas (Turkiye) Corporation (TBNG) during 2011, and management excluded from its assessment of effectiveness of TransAtlantic Petroleum Ltd. s internal control over financial reporting as of December 31, 2011, Direct Bulgaria, Direct Morocco, Anschutz and TBNG s internal control over financial reporting associated with total assets of approximately 15.9% of consolidated total assets, and approximately 36.2% of consolidated net loss on the consolidated statements of TransAtlantic Petroleum Ltd. and subsidiaries as of and for the year ended December 31, 2011. Our audit of internal control over financial reporting of TransAtlantic Petroleum Ltd. also excluded an evaluation of the internal control over financial reporting of Direct Bulgaria, Direct Morocco, Anschutz and TBNG.

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We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of TransAtlantic Petroleum Ltd. and subsidiaries. The material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2011 consolidated financial statements, and this report does not affect our report dated March 23, 2012, 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. has not maintained effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

(signed) KPMG LLP

Calgary, Canada

March 23, 2012

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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 as of December 31, 2011 and 2010, and the related consolidated statements of operations and comprehensive loss, equity and cash flows for each of the years in the three-year period 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 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 TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in note 2 to the consolidated financial statements, the Company has suffered recurring losses from operations and has a working capital deficiency, which raises substantial doubt about its ability to continue as a going concern. Management s plans in regard to these matters are also described in note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAtlantic Petroleum Ltd. s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 23, 2012 expressed an adverse opinion on the effectiveness of the Company s internal control over financial reporting.

(signed) KPMG LLP

Calgary, Canada

March 23, 2012

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TransAtlantic Petroleum Ltd.

Consolidated Balance Sheets

As of December 31, 2011 and 2010

(in thousands of U.S. dollars, except share data)

	2011	2010
ASSETS		**(as adjusted)**
Current assets:		**(see note 5)**
Cash and cash equivalents	$ 15,116	$ 34,676
Accounts receivable		
Oil and natural gas sales, net	35,702	23,077
Related party		3,783
Other	6,992	6,326
Prepaid and other current assets	7,031	6,376
Deferred income taxes	2,124	991
Assets held for sale	128,117	
Total current assets	195,082	75,229
Property and equipment:		
Oil and natural gas properties (successful efforts method)		
Proved	174,577	150,407
Unproved	70,180	80,167
Equipment and other property	40,403	174,654
	285,160	405,228
Less accumulated depreciation, depletion and amortization	(49,436)	(36,382)
Property and equipment, net	235,724	368,846
Other long-term assets:		
Other assets	4,673	9,552
Deposit on acquisition		10,000
Goodwill	8,514	10,341
Total other assets	13,187	29,893
Total assets	$ 443,993	$ 473,968
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 23,954	$ 15,842
Accounts payable related party	323	969
Accrued liabilities	16,450	10,329
Loans payable	7,732	30,869
Loan payable related party	73,000	75,804
Derivative liabilities	3,716	1,612
Asset retirement obligations	3,031	
Liabilities held for sale related party	3,677	
Liabilities held for sale	23,037	
Total current liabilities	154,920	135,425
Long-term liabilities:		
Asset retirement obligations	10,503	6,943
Accrued liabilities	5,503	724
Deferred income taxes	15,508	22,835

Loan payable	78,000	27,147
Loans payable related party		2,932
Derivative liabilities	3,355	1,905
Total long-term liabilities	112,869	62,486
Total liabilities	267,789	197,911
Commitments and contingencies		
Shareholders equity:		
Common shares, $0.01 par value, 1,000,000,000 shares authorized, 365,790,492 issued and outstanding as of December 31, 2011 and 336,442,984 as of December 31, 2010	3,658	3,364
Additional paid-in capital	534,117	465,973
Accumulated other comprehensive income (loss)	(50,615)	1,833
Accumulated deficit	(310,956)	(195,113)
Total shareholders equity	176,204	276,057
Total liabilities and shareholders equity	$ 443,993	$ 473,968

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

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TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Operations and Comprehensive Loss

For the years ended December 31, 2011, 2010 and 2009

(U.S. dollars and shares in thousands, except per share amounts)

	2011	2010 (as adjusted) (see note 5)	2009
Revenues:			
Oil and natural gas sales	$ 124,185	$ 69,839	$ 27,681
Other	2,153	1,015	67
Total revenues	126,338	70,854	27,748
Costs and expenses:			
Production	17,934	20,286	10,077
Exploration, abandonment and impairment	60,234	12,691	14,790
Seismic and other exploration	9,627	16,883	14,602
Contingent consideration and contingencies	6,000		
General and administrative	35,388	26,049	15,227
Depreciation, depletion and amortization	41,655	16,436	4,371
Accretion of asset retirement obligations	1,142	470	164
Total costs and expenses	171,980	92,815	59,231
Operating loss	(45,642)	(21,961)	(31,483)
Other (expense) income:			
Interest and other expense	(13,464)	(7,055)	(2,303)
Interest and other income	937	267	172
Loss on commodity derivative contracts	(8,426)	(1,624)	(1,922)
Foreign exchange loss	(11,730)	(1,872)	(3,445)
Total other expense	(32,683)	(10,284)	(7,498)
Loss from continuing operations before income taxes	(78,325)	(32,245)	(38,981)
Current income tax expense	(2,386)	(2,076)	(2,134)
Deferred income tax benefit	5,491	2,826	1,054
Loss from continuing operations	$ (75,220)	$ (31,495)	$ (40,061)
Loss from discontinued operations, net of taxes	(40,623)	(38,251)	(21,956)
Net loss	(115,843)	(69,746)	(62,017)
Net loss attributable to non-controlling interest, net of tax			(129)
Net loss attributable to common shareholders	$ (115,843)	$ (69,746)	$ (62,146)
Other comprehensive (loss) gain:			
Foreign currency translation adjustment	(52,448)	(7,768)	9,601
Comprehensive loss	$ (168,291)	$ (77,514)	$ (52,545)

Net loss per common share attributable to common shareholders:			
Basic and diluted net loss attributable to common shareholders, per common share:			
From continuing operations	$ (0.21)	$ (0.10)	$ (0.19)
From discontinued operations	$ (0.11)	$ (0.12)	$ (0.10)
Basic and diluted weighted average shares outstanding	355,971	312,488	212,320

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

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TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Equity

For the years ended December 31, 2011, 2010 and 2009

(U.S. dollars and shares in thousands)

	Common Shares	Common Shares ($)	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Non-Controlling Interest	Total Shareholders Equity
Balance at December 31, 2008	154,958		138,290		(63,350)		74,940
Issuance of common shares	147,426	3,033	248,615				251,648
Issuance of common shares and warrants in connection with the acquisition of Incremental Petroleum Limited	102		278				278
Issuance costs			(12,058)				(12,058)
Exercise of stock options	780		575				575
Share-based compensation			1,640				1,640
Non-controlling interest						129	129
Foreign currency translation adjustments				9,601			9,601
Net loss attributable to common shareholders					(62,017)	(129)	(62,146)
Balance at December 31, 2009	303,266	3,033	377,340	9,601	(125,367)		264,607
Issuance of common shares	30,357	304	84,696				85,000
Issuance costs			(4,350)				(4,350)
Issuance of warrants			4,330				4,330
Exercise of warrants	731	7	871				878
Exercise of stock options	1,212	12	1,078				1,090
Issuance of restricted stock units	877	8	(8)				
Share-based compensation			2,016				2,016
Foreign currency translation adjustments				(7,768)			(7,768)
Net loss attributable to common shareholders					(69,746)		(69,746)
Balance at December 31, 2010	336,443	$ 3,364	$ 465,973	$ 1,833	$ (195,113)	$	$ 276,057
Issuance of common shares	27,424	274	65,763				66,037
Exercise of warrants	80	1	95				96
Exercise of stock options	845	8	620				628
Issuance of restricted stock units	998	11	(11)				
Share-based compensation			1,677				1,677
Foreign currency translation adjustments				(52,448)			(52,448)
Net loss attributable to common shareholders					(115,843)		(115,843)
Balance at December 31, 2011	365,790	$ 3,658	$ 534,117	$ (50,615)	$ (310,956)	$	$ 176,204

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

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TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Cash Flows

For the years ended December 31, 2011, 2010 and 2009

(in thousands of U.S. dollars)

	2011	2010 (as adjusted) (see note 5)	2009
Operating activities:			
Net loss	$ (115,843)	$ (69,746)	$ (62,017)
Adjustment for net loss from discontinued operations	40,623	38,251	21,956
Net loss from continuing operations	(75,220)	(31,495)	(40,061)
Adjustments to reconcile net loss to net cash used in operating activities:			
Share-based compensation	1,677	2,016	1,640
Foreign currency loss (gain)	14,690	597	(492)
Unrealized loss on commodity derivative contracts	3,572	1,595	1,922
Amortization of loan financing costs	1,630	1,336	
Deferred income tax benefit	(5,491)	(2,826)	(1,054)
Amortization of warrants related party	1,972	2,358	
Exploration, abandonment and impairment	52,638	5,343	290
Depreciation, depletion and amortization	41,655	16,436	4,371
Accretion of asset retirement obligations	1,142	470	164
Loss on contingent consideration and contingencies	6,000		
Changes in operating assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(1,823)	(19,135)	(3,138)
Prepaid expenses and other assets	(4,492)	5,959	(5,822)
Accounts payable and accrued liabilities	13,607	(1,963)	7,520
Net cash provided by (used in) operating activities from continuing operations	51,557	(19,309)	(34,660)
Net cash used in operating activities from discontinued operations	(11,067)	(24,187)	(16,182)
Net cash provided by (used in) operating activities	40,490	(43,496)	(50,842)
Investing activities:			
Deposit on acquisition		(10,000)	
Acquisitions, net of cash	(747)	(96,248)	(58,069)
Additions to oil and natural gas properties	(68,519)	(52,664)	(10,349)
Additions to equipment and other properties	(3,137)	(11,405)	(23,941)
Restricted cash	5,132	(173)	
Net cash used in investing activities from continuing operations	(67,271)	(170,490)	(92,359)
Net cash used in investing activities from discontinued operations	(4,761)	(48,517)	(30,931)
Net cash used in investing activities	(72,032)	(219,007)	(123,290)
Financing activities:			
Exercise of stock options and warrants	722	1,968	575
Issuance of common shares		80,000	181,481
Issuance of common shares related party		5,000	70,167
Issuance costs		(4,350)	(12,058)
Loan proceeds	35,967	55,886	95
Loan proceeds related party		91,500	64,621
Loan repayment	(18,024)	(2,445)	(4,722)
Loan repayment related party		(18,500)	(64,621)
Loan financing costs		(1,028)	(1,834)

Net cash provided by financing activities from continuing operations	18,665	208,031	233,704
Net cash used in financing activities from discontinued operations	(5,068)	(1,134)	
Net cash provided by financing activities	13,597	206,897	233,704
Effect of exchange rate changes on cash	(1,615)	(202)	860
Net (decrease) increase in cash and cash equivalents	(19,560)	(55,808)	60,432
Cash and cash equivalents, beginning of year	34,676	90,484	30,052
Cash and cash equivalents, end of year	$ 15,116	$ 34,676	$ 90,484
Supplemental disclosures:			
Cash paid for interest	$ 10,106	$ 3,062	$ 2,578
Cash paid for income taxes	$ 7,729	$ 5,649	$ 2,073
Supplemental non-cash investing and financing activities:			
Issuance of common shares for acquisitions	$ 66,037	$	$ 278
Repayment of short-term credit facility from refinancing	$ 30,000	$	$

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

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TransAtlantic Petroleum Ltd.

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 hold interests in developed and undeveloped oil and natural gas properties in Turkey, Bulgaria and Romania. As of March 1, 2012, approximately 40% of our outstanding common shares were beneficially owned by N. Malone Mitchell, 3rd, our chief executive officer and chairman of the 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 U.S. (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.

2. Going concern

These consolidated financial statements have been prepared on the basis of accounting principles applicable to a going concern. These principles assume that we will be able to realize our assets and discharge our obligations in the normal course of operations for the foreseeable future.

We incurred a net loss for each of the last three fiscal years, including a net loss of $115.8 million during the year ended December 31, 2011, which includes a net loss from discontinued operations of $40.6 million. At December 31, 2011, the outstanding principal amount of our debt was $163.8 million, of which $5.0 million was classified as held for sale, and we had a working capital deficit from continuing operations of $61.2 million. Of our outstanding debt, $73.0 million under our credit agreement with Dalea Partners, LP (Dalea) is due upon the earlier of (i) June 30, 2012 or (ii) the later of (x) two business days after demand by Dalea or (y) the closing of the sale of our oilfield services business, which is substantially comprised of our wholly owned subsidiaries Viking International Limited (Viking International) and Viking Geophysical Services, Ltd. (Viking Geophysical) (see note 21). On March 15, 2012, we entered into a stock purchase agreement to sell Viking International and Viking Geophysical and a $15.0 million credit facility with Dalea to provide us with additional liquidity for general corporate purposes. Should we be unable to consummate the sale, raise additional financing or extend the maturity date of the Dalea credit agreement, we will not have sufficient funds to continue operations beyond June 30, 2012. As a result of the recurring losses from operations and a working capital deficiency, there is substantial doubt regarding our ability to continue as a going concern. The continuing application of the going concern assumption is dependent upon our continuing ability to obtain the necessary financing to discharge our existing obligations, fund ongoing exploration, development and operations and ultimately achieve profitable operations.

Management believes the going concern assumption to be appropriate for these financial statements. If the going concern assumption was not appropriate, adjustments would be necessary to the carrying values of assets and liabilities, reported revenues and expenses and in the balance sheet classifications used in these consolidated financial statements.

TransAtlantic Petroleum Ltd.

Notes to Consolidated Financial Statements (Continued)

3. 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 on consolidation.

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.

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, recognize the change in a derivative 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 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.

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

Foreign currency translation

Effective January 1, 2009, we determined that the functional currency of our corporate entities in Morocco, Turkey, Canada and Romania had changed from the U.S. Dollar to the Moroccan Dirham, New Turkish Lira, Canadian Dollar and the Romanian New Leu, respectively. We had contractual obligations and commitments that will result in increasing levels of transactions conducted in these currencies. In recognition of these contractual obligations and commitments combined with the expected increases in future revenues and expenditures in these countries, we determined the appropriate functional currency was the local currency for each of these subsidiaries. The functional currency of TransAtlantic Petroleum Ltd. changed from the Canadian Dollar to the U.S. Dollar effective October 1, 2009, the date upon which TransAtlantic Petroleum Ltd. continued its existence out of Canada to Bermuda.

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 re-measuring transactions and monetary accounts in a currency other than the functional currency are included in earnings. For certain of our controlled entities, 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 balance sheet as a component of accumulated other comprehensive income (loss). The accounting basis of the assets and liabilities affected by the change are adjusted to reflect the difference between the exchange rate when the asset or liability arose and the exchange rate on the date of the change.

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.

Equipment and other property

Equipment and other property are stated at 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 operations.

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

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. Oil and natural gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset 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 an independent expert. 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 estimated potential reserves and future net revenues from an independent expert, the Company s history in exploring the area, the Company s future drilling plans per its capital drilling program, prepared by the Company s reservoir engineers and operations management and other factors associated with the area. Impairment is taken on the unproved property cost 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*, goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise.

Impairment tests involve comparing the estimated fair value of the business operations with which goodwill is associated to its recorded value. Losses, if any, resulting from impairment tests are reflected in operating income in the statement of operations. 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. Drilling services revenues are recognized when the related service is performed.

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

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 income in the period that includes the enactment date.

Pursuant to ASC 740, we do not have any unrecognized tax benefits other than those for which a valuation allowance has been provided thereon. 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 benefits as a component of income tax expense.

Comprehensive income

ASC 220, *Comprehensive Income* (ASC 220), 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 will be accounted for by applying the acquisition method. Accordingly, transaction costs related to acquisitions are to be recorded as a reduction of earnings in the period they are incurred and costs related to issuing debt or equity securities that are related to the transaction will continue to be recognized in accordance with other applicable rules under U.S. GAAP. ASC 810-10-65 requires non-controlling interests to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for non-controlling interests and transactions with non-controlling interest holders in consolidated financial statements.

Per share information

Basic per share amounts are calculated using the weighted average common shares outstanding during the year. 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.

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

4. New accounting pronouncements

In January 2010, FASB issued Accounting Standards Update (ASU) 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06). The update provides amendments to ASC 820 that require more robust disclosures about: (1) the different classes of assets and liabilities measured at fair value, (2) the valuation techniques and inputs used, (3) the activity in Level 3 fair value measurements, and (4) the transfers between Levels 1, 2, and 3. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009. Disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The adoption of ASU 2010-06 did not have a material impact on our financial statements.

In December 2010, FASB issued ASU 2010-28, *Intangibles Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (ASU 2010-28). ASU 2010-28 modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The update is effective for interim and annual reporting periods beginning after December 15, 2010. This update is considered on an interim and annual basis when we review and perform our goodwill impairment test. The adoption of ASU 2010-28 did not have a material impact on our financial statements.

In December 2010, FASB issued ASU 2010-29, *Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29). ASU 2010-29 specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The update also expands the supplemental pro forma disclosures under ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The update is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The adoption of ASU 2010-29 did not have a material impact on our financial statements.

In May 2011, FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04). ASU 2011-04 amends ASC 820, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurement and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 will be effective for interim and annual periods beginning after December 15, 2011. The adoption of ASU 2011-04 is not expected to have a material effect on our financial statements, but may require certain additional disclosures.

In June 2011, FASB issued ASU 2011-05, *Presentation of Comprehensive Income* (ASU 2011-05). ASU 2011-05 requires the presentation of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. In December 2011, FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU 2011-05* (ASU 2011-12). ASU 2011-12 defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

of net income and other comprehensive income. The amendments will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of ASU 2011-05 is not expected to have a material effect on our financial statements, but may require a change in the presentation of our comprehensive income from the notes of the financial statements, where it is currently disclosed, to the face of the financial statements.

In September 2011, FASB issued ASU 2011-08, *Intangibles Goodwill and Other (Topic 350): Testing Goodwill for Impairment* (ASU 2011-08). ASU 2011-08 allows both public and nonpublic entities an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity would no longer be required to calculate the fair value of a reporting unit unless the entity determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. ASU 2011-08 allows early adoption and will be effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We are presently assessing the impact of ASU 2011-08.

In December 2011, FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210), Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11). ASU 2011-11 will require entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. Application of ASU 2011-11 is required for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. At that time we will make the necessary disclosures.

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.

5. Acquisitions

TBNG

On June 7, 2011, TransAtlantic Worldwide, Ltd. (TransAtlantic Worldwide) acquired Thrace Basin Natural Gas (Turkiye) Corporation (TBNG) in exchange for cash consideration of $10.5 million and the issuance of 18,500,000 of our common shares (at a deemed price of $2.05 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 18,500,000 common shares	37,925
Fair value of total consideration transferred	$ 48,429

Acquisition-Related Costs:

Included in general and administrative expenses on our consolidated statement of operations and comprehensive loss for the year ended December 31, 2011	$ 1,013

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

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	35,108
Total identifiable net assets	$ 48,429

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 property and deferred tax adjustments.

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

	Revenue	Loss
	(in thousands)	
Actual from June 7, 2011 through December 31, 2011	$ 13,466	$ (4,154)

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) for cash consideration of $2.4 million and the issuance of 8,924,478 of our common shares (at a deemed price of $3.15 per common share) to the seller, Direct Petroleum Exploration, Inc. (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.

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

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 8,924,478 common shares	28,112
Liability classified contingent consideration	4,000
Fair value of total consideration transferred	$ 34,520

If certain post-closing milestones are achieved, we will issue additional consideration to Direct equal to: (i) $10.0 million worth of our common shares if the Deventci-R2 well in Bulgaria is a commercial success and (ii) $10.0 million worth of our common shares if Direct Bulgaria receives a production concession for a specified area in Bulgaria. The fair value of these contingent liabilities represent our best estimate of the amounts to be paid for the additional contingent consideration. Subsequent changes in the fair value of the contingent consideration liabilities are reflected in our statement of operations. The fair value of this contingent consideration was $0 at December 31, 2011 and the reversal of the liability classified contingent consideration on acquisition was included under the caption Contingent consideration and contingencies on our consolidated statement of operations and comprehensive loss for the year ended December 31, 2011.

Acquisition-Related Costs:

Included in general and administrative expenses on our consolidated statement of operations and comprehensive loss for the year ended December 31, 2011	$ 117

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

Assets:	
Cash	$ 320
Accounts receivable	57
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	79
Total oil and natural gas properties and other equipment	34,119
Liabilities:	
Accounts payable, consisting of normal trade obligations	122

Total identifiable net assets	$ 34,520

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

The results of operations of Direct Morocco, Anschutz and Direct Bulgaria are included in our consolidated results of operations 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 operations and comprehensive loss for the year ended December 31, 2011 are shown below:

	Revenue	Loss
	(in thousands)	
Continuing operations	$ 483	$ (30,749)[(1)]
Discontinued operations		(7,021)
Total from February 18, 2011 through December 31, 2011	$ 483	$ (37,770)

(1) See footnote 7 for a discussion of impairment.

Amity and Petrogas

On August 25, 2010, TransAtlantic Worldwide acquired all of the shares of Amity Oil International Pty Ltd (Amity) and Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş. (Petrogas) in exchange for total cash consideration of $96.5 million. Through the acquisition of Amity and Petrogas, TransAtlantic Worldwide acquired interests ranging from 50% to 100% in 18 exploration licenses, one production lease and equipment. We funded $66.5 million of the purchase price from borrowings under our credit agreement with Dalea (see note 11) and $30.0 million of the purchase price from borrowings under our short-term secured credit agreement with Standard Bank Plc (Standard Bank) (see note 10).

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 Amity and Petrogas acquisition and the final recognized amounts of assets acquired and liabilities assumed which have been recognized at the acquisition date.

Consideration:

	(in thousands)
Payment of cash for the acquisition of all the shares of Amity and 99.6% of the shares of Petrogas	$ 96,347
Payment of cash for the acquisition of 0.4% of the shares of Petrogas from non-controlling interest in Petrogas	200
Fair value of total consideration transferred	$ 96,547

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TransAtlantic Petroleum Ltd.

Notes to Consolidated Financial Statements (Continued)

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

Assets:	
Cash	$ 299
Accounts receivable	295
Total financial assets	594
Other current assets, consisting primarily of prepaid expenses	1,721
Oil and natural gas properties:	
Unproved properties	56,722
Proved properties	47,712
Drilling services and related equipment	4,256
Inventory	3,032
Total oil and natural gas properties, drilling services and other equipment	111,722
Liabilities:	
Accounts payable, consisting of normal trade obligations	198
Accrued liabilities, consisting primarily of accrued compensated employee absences	677
Deferred income taxes	16,063
Asset retirement obligations, consisting of future plugging and abandonment liabilities on Amity s and Petrogas developed wellbores as of August 25, 2010, based on internal and third-party estimates of such costs, adjusted for a historic Turkish inflation rate of approximately 6.5%, and discounted to present value using the Company s credit-adjusted risk-free rate of 7.2%	552
Total liabilities	17,490
Total identifiable net assets	$ 96,547

We finalized the purchase accounting on receipt of the final valuation report. This resulted in adjustments to our 2010 financial statements, being a reduction of proved properties of $7.1 million, an increase of unproved properties by $7.0 million and a decrease in deferred income taxes of $0.1 million. Under ASC 805, a change to the initial purchase price allocation is recast as if the final valuations had been recorded on the date of the acquisition. Due to the change in proved properties fair values, our depletion expense decreased by $1.4 million, net of tax in 2010 and by $2.2 million, net of tax in 2011.

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

Pro forma results of operations

The following table presents the unaudited pro forma results of operations as though the acquisitions of Amity, Petrogas, Direct Morocco, Anschutz, Direct Bulgaria and TBNG had occurred as of January 1, 2010 and the acquisitions of Direct Morocco, Anschutz, Direct Bulgaria and TBNG had occurred as of January 1, 2011 (in thousands, except per share amounts):

	Unaudited	
	December 31, 2011 (in thousands)	December 31, 2010 (in thousands)
Total revenues	$ 138,396	$ 113,658
Loss from continuing operations before income taxes	(73,647)	(33,632)
Loss from continuing operations	(71,473)	(34,292)
Loss from discontinued operations	(44,268)	(40,688)
Net loss	(115,741)	(74,980)
Net loss per common share from continuing operations		
Basic	$ (0.20)	$ (0.10)
Diluted	$ (0.20)	$ (0.10)
Net loss per common share from discontinued operations		
Basic	$ (0.12)	$ (0.12)
Diluted	$ (0.12)	$ (0.12)

6. 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, 2011 and 2010:

	2011	2010
	(in thousands)	
Goodwill at January 1,	$ 10,341	$ 10,067
Foreign exchange change effect	(1,827)	274
Goodwill at December 31,	$ 8,514	$ 10,341

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

7. Property and equipment

(a) *Oil and natural gas properties*. The following table sets forth the capitalized costs under the successful efforts method for oil and natural gas properties:

	December 31, 2011	December 31, 2010
	(in thousands)	
Oil and natural gas properties, proved:		
Turkey	$ 172,886	$ 150,407
Bulgaria	1,691	
Total oil and natural gas properties, proved	174,577	150,407
Oil and natural gas properties, unproved:		
Turkey	70,180	73,662
Morocco		5,036
U.S		1,469
Total oil and natural gas properties, unproved	70,180	80,167
Accumulated depletion	(45,327)	(14,360)
Net oil and natural gas properties	$ 199,430	$ 216,214

At December 31, 2011 and 2010, we excluded $7.1 million and $11.7 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, 2011, the capitalized costs of our oil and natural gas properties included $61.8 million relating to acquisition costs of proved properties which are being amortized by the unit-of-production method using total proved reserves and $60.4 million relating to exploratory well costs and additional development costs which are being amortized by the unit-of-production method using proved developed reserves.

At December 31, 2010, the capitalized costs of our oil and natural gas properties included $86.8 million relating to acquisition costs of proved properties which are being amortized by the unit-of-production method using total proved reserves and $37.6 million relating to exploratory well costs and additional development costs which are being amortized by the unit-of-production method using proved developed reserves.

During the year ended December 31, 2011, we incurred approximately $19.6 million in exploratory drilling costs, of which $7.4 million was charged to earnings (included in exploration, abandonment and impairment expense) and $12.1 million remained capitalized at year end. We transferred $5.0 million of our exploratory well costs to proved properties in 2011. No amount of our exploratory well costs as of December 31, 2011 have been capitalized for a period of greater than one year after completion of drilling.

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. We recorded a $30.2 million impairment on our unproved oil and natural gas properties during the year ended December 31, 2011. Of this amount, $25.9 million was attributable to our Bulgarian properties. We impaired the Bulgarian properties following the enactment of legislation by the Bulgarian Parliament, which bans fracture stimulation in the Republic of Bulgaria. We recorded no impairment on our unproved oil and natural gas properties for the years ended December 31, 2010 and 2009.

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

TransAtlantic Petroleum Ltd.

Notes to Consolidated Financial Statements (Continued)

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 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. We recorded $14.6 million in impairment charges on two of our proved properties for the year ended December 31, 2011 primarily due to downward revisions in natural gas reserves in the Alpullu and Edirne fields. No impairment was recorded for the years ended December 31, 2010 and 2009.

Uncertainties affect the recoverability of these costs as the recovery of the costs outlined above are dependent upon us obtaining government approvals, obtaining and maintaining licenses in good standing and achieving commercial production or sale.

(b) *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,	
	2011	**2010**
	(in thousands)	
Other equipment	$ 6,351	$ 83,916
Inventory	20,471	37,569
Gas gathering system and facilities	6,822	7,960
Fracture stimulation equipment		16,410
Seismic equipment		14,882
Vehicles	1,001	9,324
Office equipment and furniture	5,758	4,593
Gross equipment and other property	40,403	174,654
Accumulated depreciation	(4,109)	(22,022)
Net equipment and other property	$ 36,294	$ 152,632

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, 2011, we excluded $0.5 million of other equipment, $20.5 million of inventory and $1.8 million of gas gathering system and facilities from depreciation as the equipment had not been placed into service.

At December 31, 2010, we excluded $0.4 million of other equipment and $37.6 million of inventory from depreciation as the equipment had not been placed into service.

8. 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 financial instruments as hedges for accounting purposes, and accordingly, we record the contracts at fair value and recognize changes in fair value in earnings as they occur.

Our commodity derivative contracts are carried at their fair value on our consolidated balance sheet under either the caption Derivative liabilities or Derivative assets. To the extent that a legal right-of-offset exists, we net the value of our derivative instruments with the same counterparty in our consolidated balance

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

sheets. All of our oil derivative contracts are settled based upon Brent oil pricing. We recognize unrealized and realized gains and losses related to these contracts on a fair value basis in our consolidated statements of operations and comprehensive loss under the caption Gain (loss) on commodity derivative contracts. Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows.

During the year ended December 31, 2011, we recorded a net loss on commodity derivative contracts of $8.4 million, consisting of a $3.6 million unrealized loss for changes in fair value and a $4.8 million realized loss for settled contracts.

During the year ended December 31, 2010, we recorded a net unrealized loss on commodity derivative contracts of $1.6 million and a realized loss on commodity derivative contracts of $29,000.

At December 31, 2011, we had outstanding 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, 2011

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (Liability) (in thousands)
Collar	January 1, 2012 December 31, 2012	960	$ 64.69	$ 106.98	$ (2,529)
Collar	January 1, 2013 December 31, 2013	400	$ 75.00	$ 125.50	(116)
Collar	January 1, 2014 December 31, 2014	380	$ 75.00	$ 124.25	12
					$ (2,633)

Type	Period	Quantity (Bbl/day)	Collars Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Additional Call Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (Liability) (in thousands)
Three-way collar contract	January 1, 2012 December 31, 2012	240	$ 70.00	$ 100.00	$ 129.50	$ (764)
Three-way collar contract	January 1, 2012 March 31, 2012	350	$ 85.00	$ 118.88	$ 138.13	(7)
Three-way collar contract	April 1, 2012 June 30, 2012	350	$ 85.00	$ 116.25	$ 137.38	(35)
Three-way collar contract	July 1, 2012 December 31, 2012	205	$ 85.00	$ 97.13	$ 162.13	(381)
Three-way collar contract	January 1, 2013 December 31, 2013	831	$ 85.00	$ 97.13	$ 162.13	(1,985)
Three-way collar contract	January 1, 2014 December 31, 2014	726	$ 85.00	$ 97.13	$ 162.13	(626)

Three-way collar contract	January 1, 2015	December 31, 2015	1,016	$	85.00	$	91.88	$	151.88	(640)
									$ (4,438)

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Notes to Consolidated Financial Statements (Continued)

At December 31, 2010, we had outstanding 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, 2010

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, 2011	December 31, 2011	1,060	$ 64.39	$ 101.32	$ (1,342)
Collar	January 1, 2012	December 31, 2012	960	$ 64.69	$ 106.98	(1,571)
						$ (2,913)

Type	Period		Quantity (Bbl/day)	Collars Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Additional Call Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Three-way collar contract	January 1, 2011	December 31, 2011	240	$ 70.00	$ 100.00	$ 129.50	$ (270)
Three-way collar contract	January 1, 2012	December 31, 2012	240	$ 70.00	$ 100.00	$ 129.50	(334)
							$ (604)

9. 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, 2011, the net present value of our total ARO was estimated to be $13.5 million, with the undiscounted value being $22.1 million. Total ARO at December 31, 2011 shown in the table below consists of amounts for future plugging and abandonment liabilities on our wellbores and facilities based on internal and third-party estimates of such costs, adjusted for inflation at a rate of approximately 5.5% per annum, and discounted to present value using our credit-adjusted risk-free rate of 5.8% and 7.2% per annum for the years ended December 31, 2011 and 2010, respectively. The following table summarizes the changes in our ARO for the years ended December 31, 2011 and 2010:

	2011	2010
	(in thousands)	
Asset retirement obligation January 1,	$ 6,943	$ 3,125
Acquisitions	6,480	552

Change in estimates	512	2,220
Liabilities settled	(195)	
Foreign exchange change effect	(2,524)	(251)
Additions	1,176	827
Accretion expense	1,142	470
Asset retirement obligation at December 31,	13,534	6,943
Less: current portion	3,031	
Long-term portion	$ 10,503	$ 6,943

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Notes to Consolidated Financial Statements (Continued)

10. Third-party loans payable

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

	December 31, 2011	December 31, 2010
	(in thousands)	
Third-Party Floating Rate Debt		
Amended and Restated Credit Facility	$ 78,000	$ 25,000
Short-term secured credit agreement		30,000
TEMI unsecured credit agreements		126
Third-Party Fixed Rate Debt		
TBNG credit agreements	7,732	
Viking International equipment loan	(1)	2,890
Total third-party debt	85,732	58,016
Less: short-term third-party debt	7,732	30,869
Long-term third-party debt	$ 78,000	$ 27,147

(1) $2.1 million outstanding at December 31, 2011, classified as Liabilities held for sale .

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. (TAT) and Petrogas (collectively, and together with Amity, the Borrowers) entered into the amended and restated senior secured credit facility with Standard Bank and BNP Paribas (Suisse) SA (the Amended and Restated Credit Facility). Each of the Borrowers are our wholly owned subsidiaries. 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 (collectively, the Guarantors).

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, 2011, the lenders had aggregate commitments of $120.0 million, with individual commitments of $60.0 million each. On the last day of each fiscal quarter commencing September 30, 2012 and at the maturity date, the lenders commitments are subject to reduction by 6.25% of their commitments existing on such commitment reduction date.

The borrowing base is re-determined semi-annually on April 1st and October 1st of each year prior to September 30, 2012 and quarterly on January 1st, April 1st, July 1st and October 1st of each year after September 30, 2012. Following our semi-annual borrowing base redetermination on October 1, 2011, our borrowing base is currently $81.4 million.

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.

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Notes to Consolidated Financial Statements (Continued)

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 uncancelled 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 London Interbank Offered Rate (LIBOR) plus 5.50% per annum.

The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.75% per annum of the unused and uncancelled 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) 1.65% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Amended and Restated Credit Facility, (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.

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.

At December 31, 2011, the Borrowers had borrowed $78.0 million and were in compliance with all material covenants under the Amended and Restated Credit Facility.

If an event of default shall occur and be continuing, all loans under the Amended and Restated Credit Facility will bear an additional interest rate of 2.00% per annum. In the case of an event of default upon bankruptcy or insolvency, all amounts payable under the Amended and Restated Credit Facility become immediately due and payable. In the case of any other event of default, all amounts due under the Amended and Restated Credit Facility may be accelerated by the lenders or the administrative agent. Borrowers have certain rights to cure an event of default arising from a violation of the fixed charge coverage ratio or the interest coverage ratio by obtaining cash equity or loans from us.

Short-term secured credit agreement

On August 25, 2010, TransAtlantic Worldwide entered into a short-term secured credit agreement with Standard Bank pursuant to which TransAtlantic Worldwide borrowed $30.0 million from Standard Bank. The short-term secured credit agreement was guaranteed by us and each of TransAtlantic Petroleum (USA) Corp., Amity and Petrogas. TransAtlantic Worldwide used the proceeds of the short-term secured credit agreement to finance a portion of the purchase price for the shares of Amity and Petrogas. Borrowings under

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

the short-term secured credit agreement accrued interest at a rate of LIBOR plus the applicable margin. The applicable margin equaled 3.75% for interest that accrued before November 23, 2010, 4.00% for interest that accrued on or after November 23, 2010 and before February 20, 2011 and 4.25% for interest that accrued on or after February 20, 2011 and before May 25, 2011. In addition, TransAtlantic Worldwide paid an arrangement fee of $750,000.

The short-term secured credit agreement was scheduled to mature on May 25, 2011. TransAtlantic Worldwide repaid the loan in full on May 24, 2011, at which time the short-term secured credit agreement was terminated.

TBNG credit agreements

TBNG is a party to unsecured credit agreements with a Turkish bank. During September 2011, we repaid the outstanding balance of approximately $4.1 million on one of the agreements. At December 31, 2011, there were outstanding borrowings of approximately 14.6 million New Turkish Lira (approximately $7.7 million) under the remaining credit agreement. Borrowings under the credit agreement bear interest at a rate of 14% per annum, and interest is payable quarterly. The credit agreement matures on September 13, 2012 and may be renewed for an additional period on the same terms.

Viking International equipment loan

In 2010, Viking International entered into a secured credit agreement with a Turkish bank to fund the purchase of vehicles. The credit agreement has a term of 48 months, matures on July 20, 2014, bears interest at an annual rate of 3.84% and is secured by the vehicles purchased with the proceeds of the loan. There is no further availability under the credit agreement. As of December 31, 2011, the outstanding balance under the secured credit agreement was $2.1 million and the secured credit agreement was included in Liabilities held for sale in our consolidated balance sheets.

TEMI credit agreement

TEMI is party to unsecured, non-interest bearing stand-by credit agreements with a Turkish bank. At December 31, 2011, there were no outstanding borrowings.

11. Related party loans payable

We use negotiated interest rates in determining the fair value of our debt. As of the indicated dates, our related-party debt consisted of the following:

	December 31, 2011	December 31, 2010
	(in thousands)	
Related Party Floating Rate Debt		
Dalea Credit Agreement	$ 73,000	$ 73,000
Dalea Credit Agreement discount warrants		(1,972)
	73,000	71,028
Viking Drilling note	(1)	7,708
Total related party debt	73,000	78,736
Less: Short-term related party debt	73,000	75,804

Long-term related party debt	$	$ 2,932

(1) $2.9 million outstanding at December 31, 2011, classified as Liabilities held for sale related party .

Dalea credit agreement

On June 28, 2010, we entered into a credit agreement with Dalea (the Dalea Credit Agreement). Dalea is 100% owned by Mr. Mitchell and his wife. The purpose of the Dalea Credit Agreement was (i) to fund the acquisition of all of the shares of Amity and Petrogas (see notes 5 and 18), and (ii) for general corporate purposes. The initial advance under the Dalea Credit Agreement was $50.0 million.

On May 18, 2011, we entered into a first amendment to the Dalea Credit Agreement to extend the maturity date of the credit agreement to December 31, 2011 and to increase the interest rate to match the interest rate payable under the Amended and Restated Credit Facility. On November 7, 2011, we entered into a second amendment to the Dalea Credit Agreement to extend the maturity date to the earlier of (i) March 31, 2012 or (ii) the sale of Viking International and Viking Geophysical. On March 15, 2012, we entered into a third amendment to the Dalea credit agreement to extend the maturity date until the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of our oilfield services business or (y) two business days after demand by Dalea.

Amounts due under the Dalea Credit Agreement accrue interest at a rate of three-month LIBOR plus 5.50% per annum beginning on May 1, 2011, to be adjusted monthly on the first day of each month. Prior to May 1, 2011, amounts due under the Dalea Credit Agreement accrued interest at a rate of three-month LIBOR plus 2.50% per annum. In addition, interest on the Dalea Credit Agreement will cease to accrue from April 1, 2012 until the closing date of the sale of our oilfield services business. If the closing does not occur, the abated interest will be reinstated. In addition, we are required to pay all accrued interest in arrears on the last day of each month until the date of repayment and at any time that the principal balance is due and payable. We may prepay the amounts due under the Dalea Credit Agreement at any time before maturity without penalty.

The Dalea Credit Agreement contains certain covenants that limit our ability to, among other things, (i) make, give, create or permit or attempt to make, give or create any mortgage, charge, lien or encumbrance over any of our assets or any subsidiary s assets (subject to certain specified exceptions), (ii) change our name or our jurisdiction of organization, (iii) declare or provide for any dividends or other similar payments, (iv) redeem or repurchase any of our shares, (v) make, or permit the sale of, or disposition of, any substantial or material part of our business, assets or undertaking or that of any subsidiary, (vi) borrow or cause any subsidiary to borrow money from any person (subject to certain specified exceptions) without obtaining and delivering a duly signed assignment and postponement of claim by such person in form and terms satisfactory to Dalea, (vii) pay out or permit the payment of any shareholder loans or other indebtedness to non-arm s length parties by us or any subsidiary, or (viii) guarantee or permit the guarantee of the obligations of any other person by us or any subsidiary except in the ordinary course of business. In addition, any proceeds received by us or any subsidiary from any debt financings (subject to certain specified exceptions) must be used to repay amounts outstanding under the Dalea Credit Agreement, net of reasonable transaction and financing costs. We or any subsidiary are also required to repay amounts outstanding under the Dalea Credit Agreement from (i) any proceeds of any equity issuance received from Mr. Mitchell, his immediate family or any entities owned or controlled by Mr. Mitchell or his immediate family (collectively, the Mitchell Family), and (ii) all proceeds of any equity issuance in excess of $75.0 million (excluding any proceeds received from the Mitchell Family), net of reasonable transaction costs. Amounts repaid under the Dalea Credit Agreement cannot be reborrowed. We paid Dalea s reasonable legal fees and other expenses incidental to the completion of the Dalea Credit Agreement.

Events of default under the Dalea Credit Agreement include, but are not limited to, payment defaults, defaults in the performance of any terms, covenants or conditions of the Dalea Credit Agreement or collateral documents, material misrepresentations by us or any subsidiary, we or any subsidiary ceases or threatens to cease to carry on business, the prohibition in trading in our shares or the suspension or delisting of our common shares from any stock exchange, any material adverse change occurs in us or any of our subsidiaries, Dalea believes in good faith that our ability to pay or perform any of the covenants contained in the Dalea Credit Agreement is materially impaired, our insolvency or the insolvency of any subsidiary, or a change in control of the Company. A change of control is defined as the change of ownership of, or control or direction over, directly or indirectly, 20% or more of our outstanding voting securities. If an event of default occurs and is continuing, Dalea may demand immediate payment of all monies owing under the Dalea Credit Agreement; provided, that with respect to certain specified events of default, all monies due under the Dalea Credit Agreement shall automatically become due and payable without any demand or any other action by Dalea or any other person.

In connection with our public offering of common shares from September 30, 2010 through October 8, 2010, Dalea waived its right to be repaid from our proceeds of the offering, which would have otherwise been due to Dalea under the terms of the Dalea Credit Agreement.

Under the terms of the Dalea Credit Agreement, we were required to issue Dalea 100,000 common share purchase warrants for each $1.0 million in principal amount advanced under the Dalea Credit Agreement. We borrowed an aggregate of $73.0 million under the Dalea Credit Agreement, and on September 1, 2010, we issued 7.3 million common share purchase warrants to Dalea. Of these common share purchase warrants, we were obligated to issue 5.0 million warrants when we made our initial draw of $50.0 million on June 28, 2010 and 2.3 million warrants when we made our final draw of $23.0 million on August 24, 2010. All of the warrants were actually issued on September 1, 2010. The common share purchase warrants are exercisable until September 1, 2013 and have an exercise price of $6.00 per share. The fair value of the 5.0 million common share purchase warrants issuable as a result of the June 28, 2010 draw was determined using the Black-Scholes option-pricing model (Black-Scholes Model) with the following assumptions: share price of $3.52 per share; volatility of 51%; dividend rate of 0%; risk-free interest rate of 0.5% and a term of three years. The fair value of the 2.3 million common share purchase warrants issuable as a result of the August 24, 2010 draw was determined using the Black-Scholes Model with the following assumptions: share price of $2.85 per share; volatility of 51%; dividend rate of 0%; risk-free interest rate of 0.5% and a term of three years.

The proceeds from the Dalea Credit Agreement were allocated to current debt and warrants based on relative fair values. We recorded a debt discount equal to the difference between the proceeds allocated to the debt and the stated value of the debt, which was fully amortized at December 31, 2011.

As of December 31, 2011, we had borrowed $73.0 million under the Dalea Credit Agreement. No further borrowings are permitted under the Dalea Credit Agreement.

Dalea loan and security agreement

On June 28, 2010, Viking International entered into a loan and security agreement (the Loan Agreement) with Dalea. The purpose of the Loan Agreement was to fund the purchase of equipment and for general corporate purposes.

The initial advance under the Loan Agreement was $18.5 million and was secured by (i) the equipment named therein, and (ii) proceeds of the equipment and all accessions to, substitutions and replacements for, and rents, profits and products of, each of the foregoing.

Amounts due under the Loan Agreement accrued interest at a rate of 10% per annum. Viking International was required to pay monthly principal payments in the amount of $833,333, together with a payment of all accrued interest in arrears on the last day of each month beginning October 31, 2010. Viking International could prepay the amounts due under the Loan Agreement at any time before maturity without premium or penalty.

Viking International borrowed an aggregate of $18.5 million under the Loan Agreement. We repaid the loan in full on September 30, 2010, and on December 31, 2010 the Loan Agreement was terminated.

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Notes to Consolidated Financial Statements (Continued)

Viking Drilling note

On July 27, 2009, Viking International purchased the I-13 drilling rig and associated equipment from Viking Drilling, LLC (Viking Drilling). Viking International paid $1.5 million in cash for the drilling rig and entered into a note payable with Viking Drilling in the amount of $5.9 million. The note was due and payable on August 1, 2010, bore interest at a fixed rate of 10% per annum and was secured by the drilling rig and associated equipment. We paid interest under the note on November 1, 2009 and February 1, 2010. On February 19, 2010, Viking International purchased the I-14 drilling rig and associated equipment from Viking Drilling. Viking International paid $1.5 million in cash for the I-14 drilling rig and entered into an amended and restated note payable to Viking Drilling in the amount of $11.8 million, which was comprised of $5.9 million payable related to the I-14 drilling rig and $5.9 million payable related to the purchase of the I-13 drilling rig in July 2009. Under the terms of the amended and restated note, interest is payable monthly at a floating rate of LIBOR plus 6.25%, and the amended and restated note is due and payable August 1, 2012. The amended and restated note is secured by the I-13 and I-14 drilling rigs and associated equipment. As of December 31, 2011, the outstanding balance under the note was $2.9 million and the note is included in Liabilities held for sale related party in our consolidated balance sheets. Dalea owns 85% of Viking Drilling.

12. Shareholders equity

June 2011 share issuance

On June 7, 2011, we issued 18,500,000 common shares at a deemed price of $2.05 per common share in a private placement to an accredited investor in connection with the acquisition of TBNG.

February 2011 share issuance

On February 18, 2011, we issued 8,924,478 common shares at a deemed price of $3.15 per common share in a private placement to an accredited investor in connection with the acquisition of Direct Morocco, Anschutz and Direct Bulgaria.

September 2010 share issuance

From September 30, 2010 through October 8, 2010, we closed a public offering of an aggregate of 30,357,143 common shares at a purchase price of $2.80 per common share (the Offering), raising gross proceeds of $85.0 million. Of the 30,357,143 common shares sold, we offered and sold 1,788,643 common shares to Dalea. The net proceeds from the Offering, after deducting the placement agency fee and offering expenses, were approximately $80.6 million. We used $19.0 million of the net proceeds for the repayment of the principal amount and accrued interest under the Loan Agreement with Dalea (see note 11) and used the remaining net proceeds for general corporate purposes.

September 2010 warrant issuance

In September 2010, we issued 7.3 million common share purchase warrants to Dalea pursuant to the Dalea Credit Agreement (see note 11). The common share purchase warrants are exercisable until September 1, 2013 and have an exercise price of $6.00 per share. The fair value of the common share purchase warrants is $2.0 million using the Black-Scholes Model.

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.

Share-based compensation expense of $1.7 million, $2.0 million, and $1.2 million with respect to RSU awards was recorded for the years ended December 31, 2011, 2010 and 2009, respectively.

As of December 31, 2011, we had approximately $1.4 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 2.6 years. The following table sets forth RSU activity for the year ended December 31, 2011:

	Number of Units (in thousands)	Weighted Average Grant Date Fair Value
Unvested RSUs outstanding at December 31, 2010	2,466	$ 2.22
Granted	754	3.18
Forfeited	(616)	2.57
Vested	(1,175)	2.18
Unvested RSUs outstanding at December 31, 2011	1,429	$ 2.61

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. All options presently outstanding under the Option Plan have 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. For the years ended December 31, 2010 and 2009, we recognized share-based compensation expense of approximately $70,000 and $383,000, respectively, with respect to stock options. All stock options were fully vested in 2010, and therefore, no share-based compensation expense for stock option awards was recorded for the year ended December 31, 2011. We did not grant any stock options during the years ended December 31, 2011, 2010 and 2009.

Details of the Option Plan at December 31, 2011, 2010 and 2009 are presented below.

	2011		2010		2009	
	Number of Options (in thousands)	Weighted Average Exercise Price	Number of Options (in thousands)	Weighted Average Exercise Price	Number of Options (in thousands)	Weighted Average Exercise Price
Outstanding at January 1,	2,111	$ 0.86	3,323	$ 0.88	4,413	$ 0.85

Granted								
Expired	(131)		1.30				(310)	0.90
Exercised	(845)		0.74	(1,212)		0.90	(780)	0.74
Outstanding at December 31,	1,135	$	0.91	2,111	$	0.86	3,323	$ 0.88
Exercisable at December 31,	1,135	$	0.91	2,111	$	0.86	3,177	$ 0.86

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The following table summarizes information about stock options as of December 31, 2011:

Range of Prices		Options Outstanding and Exercisable			Weighted-Average Options Exercisable Remaining Contractual Life (years)
Low	High	Shares (in thousands)	Weighted-Average Exercise Price	Intrinsic Value- (in thousands)	
$0.31	$ 0.74	205	$ 0.31	$ 205	0.93
$1.00	$ 1.20	775	1.00	240	0.03
$1.23	$ 1.32	155	1.23	12	1.44
		1,135	$ 0.91	$ 457	0.38

Earnings per share

Because we reported a net loss for the years ended December 31, 2011, 2010 and 2009, we excluded the following share based awards from the computation of earnings per share, as their effect would have been anti-dilutive:

	2011	2010	2009
Unvested RSUs	1,825,124	2,190,954	1,750,625
Stock options	1,651,462	2,680,276	4,013,211
Warrants	17,275,542	12,928,604	10,582,109

Additionally, we had a contingent liability at December 31, 2011 of approximately $10.0 million that is payable in our common shares (see note 17). At the December 31, 2011 closing stock price, this liability represents 7,633,588 common shares that could be potentially dilutive to future earnings per share calculations.

13. Income taxes

On October 1, 2009, we continued out of Canada into the jurisdiction of Bermuda. The income tax provision differs from the amount that would be obtained by applying the Bermuda income tax rate of 0% (for 2011, 2010 and 2009) to loss for the year as follows:

	2011	2010 (in thousands)	2009
Statutory tax rate	0.00%	0.00%	0.00%
Loss from continuing operations before tax	$ (78,325)	$ (32,245)	$ (38,981)
Expected income tax reduction			
Increase (decrease) resulting from:			
Share-based compensation			85
Change in tax rate due to operating jurisdiction	(11,173)	(1,227)	(4,915)
Change in valuation allowance	6,871	586	(3,519)
Continuance out of Canada			8,601
Expiration of tax non capital loss carryovers	1,198		

Other	(1)	(109)	828
Total	$ (3,105)	$ (750)	$ 1,080

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Notes to Consolidated Financial Statements (Continued)

The components of the net deferred income tax liability at December 31, 2011, 2010 and 2009 were as follows:

	2011	2010 (in thousands)	2009
Deferred income tax liabilities:			
Property and equipment	$ (20,639)	$ (25,991)	$ (11,725)
Foreign exchange	(22)	227	(28)
Deferred income tax assets:			
Property and equipment	1,924	1,591	563
Operating loss carry-forwards	32,293	25,923	24,021
Foreign exchange	306		
Unrealized derivative loss	1,171	693	395
Inventories	375	455	423
Accrued liabilities and other	777	492	1,064
Provision for asset retirement	650	788	698
Trade receivables	373		
Valuation allowance	(30,592)	(26,023)	(22,887)
Net deferred tax liability	$ (13,384)	$ (21,845)	$ (7,476)

We have accumulated losses or resource-related deductions available for income tax purposes in Turkey, Romania, Bulgaria and the U.S. No recognition has been given in these consolidated financial statements to the future benefits that may result from the utilization of losses for income tax purposes. We have non-capital tax losses in Turkey of approximately 152.7 million New Turkish Lira (approximately $80.9 million), which began expiring in 2011; non-capital tax losses in Romania of approximately 16.6 million Romanian New Leu (approximately $4.9 million), which began expiring in 2011; non-capital losses in Bulgaria of approximately 5.7 million Bulgarian Lev (approximately $3.7 million), which expire commencing in 2017; and non-capital tax losses in the U.S. of approximately $35.4 million, which began expiring in 2010.

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 can still be 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.

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Notes to Consolidated Financial Statements (Continued)

14. Segment information

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

	Corporate	Romania	Turkey (in thousands)	Bulgaria	Total
For the year ended December 31, 2011					
Total revenues	$ 66	$	$ 125,789	$ 483	$ 126,338
Production	322	37	16,943	632	17,934
Exploration, abandonment and impairment		2	36,290	23,942	60,234
Seismic and other exploration	1,022	768	7,753	84	9,627
Contingent consideration and contingencies				6,000	6,000
General and administrative	14,231	358	20,793	6	35,388
Depreciation, depletion and amortization	96	31	41,036	492	41,655
Accretion of asset retirement obligations			1,131	11	1,142
Total costs and expenses	15,671	1,196	123,946	31,167	171,980
Operating (loss) income	(15,605)	(1,196)	1,843	(30,684)	(45,642)
Loss on commodity derivative contracts			(8,426)		(8,426)
Foreign exchange gain (loss)	16	(39)	(11,497)	(210)	(11,730)
Interest and other income (expense)	(7,250)	467	(6,678)	(3)	(13,464)
Interest and other income	15	12	762	148	937
Loss before income taxes	(22,824)	(756)	(23,996)	(30,749)	(78,325)
Income tax benefit			3,105		3,105
Net loss attributable to common shareholders	$ (22,824)	$ (756)	$ (20,891)	$ (30,749)	$ (75,220)
Total assets as of December 31, 2011	$ 2,940	$ 881	$ 307,891	$ 4,164	$ 315,876(1)
Goodwill as of December 31, 2011	$	$	$ 8,514	$	$ 8,514
Capital expenditures	$	$	$ 117,071	$ 35,369	$ 152,440
For the year ended December 31, 2010					
Total revenues	$ 182	$	$ 70,672	$	$ 70,854
Production	85	58	20,143		20,286
Exploration, abandonment and impairment	84	5,182	7,425		12,691
Seismic and other exploration	2,700	873	13,310		16,883
General and administrative	11,999	365	13,685		26,049
Depreciation, depletion and amortization	124	27	16,285		16,436
Accretion of asset retirement obligations			470		470
Total costs and expenses	14,992	6,505	71,318		92,815
Operating loss	(14,810)	(6,505)	(646)		(21,961)
Loss on commodity derivative contracts			(1,624)		(1,624)

Foreign exchange loss	(299)	(6)	(1,567)		(1,872)
Interest and other expense	(4,596)		(2,459)		(7,055)
Interest and other income	103	2	162		267
Loss before income taxes	(19,602)	(6,509)	(6,134)		(32,245)
Income tax benefit			750		750
Net loss attributable to common shareholders	$ (19,602)	$ (6,509)	$ (5,384)	$	$ (31,495)
Total assets as of December 31, 2010	$ 44,038	$ 3,465	$ 299,086	$	$ 346,589(1)
Goodwill as of December 31, 2010	$	$	$ 10,341	$	$ 10,341
Capital expenditures	$	$	$ 170,317	$	$ 170,317

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Notes to Consolidated Financial Statements (Continued)

	Corporate	Romania	Turkey (in thousands)	Bulgaria	Total
For the year ended December 31, 2009					
Total revenues	$ 135	$	$ 27,613	$	$ 27,748
Production	211	34	9,832		10,077
Exploration, abandonment and impairment	2,305	6,586	5,899		14,790
Seismic and other exploration	3,147	684	10,771		14,602
General and administrative	12,126	342	2,759		15,227
Depreciation, depletion and amortization	133	24	4,214		4,371
Accretion of asset retirement obligations			164		164
Total costs and expenses	17,922	7,670	33,639		59,231
Operating loss	(17,787)	(7,670)	(6,026)		(31,483)
Loss on commodity derivative contracts			(1,922)		(1,922)
Interest and other expense	(2,007)		(296)		(2,303)
Foreign exchange loss	(3,404)	(10)	(31)		(3,445)
Interest and other income	100	7	65		172
Loss before income taxes	(23,098)	(7,673)	(8,210)		(38,981)
Provision for income taxes			(1,080)		(1,080)
Net loss	(23,098)	(7,673)	(9,290)		(40,061)
Non-controlling interest, net of tax	(129)				(129)
Net loss attributable to common shareholders	$ (23,227)	$ (7,673)	$ (9,290)	$	$ (40,190)
Total assets as of December 31, 2009	$ 92,726	$ 6,278	$ 129,553	$	$ 228,557[1]
Goodwill as of December 31, 2009	$	$	$ 10,067	$	$ 10,067
Capital expenditures	$ 1,183	$ 3,017	$ 88,159	$	$ 92,359

(1) Excludes assets from our discontinued Moroccan operations and oilfield services business of $128.1 million, $127.4 million, and $78.5 million at December 31, 2011, 2010 and 2009, respectively.

15. Financial instruments

Cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities were each estimated to have a fair value approximating the carrying amount at December 31, 2011 and 2010, due to the short maturity of those 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, the Dalea Credit Agreement and amended and restated note with Viking Drilling.

Foreign currency risk

We have underlying foreign currency exchange rate exposure. Our currency exposures relate to transactions denominated in the Canadian Dollar, British Pound, Bulgarian Lev, European Union Euro, Romanian New Leu, Moroccan Dirham and New Turkish Lira. 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. The New Turkish Lira (TRY) devalued during 2011, causing fluctuations in our monetary assets and liabilities. The conversion rate to the U.S. dollar was approximately 1.89 TRY to $1.00 at December 31, 2011, compared to 1.56 TRY to $1.00 at December 31, 2010.

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

Commodity price risk

We are exposed to fluctuations in commodity prices for crude oil and natural gas. Commodity prices are affected by many factors including but not limited to supply and demand. At December 31, 2011 and 2010, we were a party to commodity derivative contracts.

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 Turkiye Petrolleri Anonim Ortakligi (TPAO), the national oil company of Turkey, Zorlu Dogal Gaz Ithalat Ihracat ve Toptan Ticaret A.S. (Zorlu), a privately owned natural gas distributor in Turkey, and Turkiye Petrol Refinerileri AŞ. (TUPRAS), a privately owned oil refinery in Turkey, 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. Other accounts receivable relating to value added taxes are due from various government agencies and are expected to be collected during April 2012. The majority of our cash and cash equivalents are held by three financial institutions in the U.S. and Turkey.

Fair value measurements

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2011:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Liabilities:				
Related party floating rate debt	$	$ (73,000)	$	$ (73,000)
Amended and Restated Credit Facility		(78,000)		(78,000)
TBNG credit agreements		(7,729)		(7,729)
Derivative financial instruments		(7,071)		(7,071)
Total	$	$ (165,800)	$	$ (165,800)

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TransAtlantic Petroleum Ltd.

Notes to Consolidated Financial Statements (Continued)

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2010:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Liabilities:				
Short-term secured credit agreement	$	$ (30,000)	$	$ (30,000)
Related party floating rate debt		(78,736)		(78,736)
Amended and Restated Credit Facility		(25,000)		(25,000)
Derivative financial instruments		(3,517)		(3,517)
Total	$	$ (137,253)	$	$ (137,253)

16. Commitments

Our aggregate annual commitments as of December 31, 2011 were as follows:

	Payments Due by Year						
	Total	2012	2013	2014	2015	2016	Thereafter
	(in thousands)						
Leases and other	$ 15,579	$ 4,819	$ 2,513	$ 1,763	$ 1,234	$ 835	$ 4,415
Contracts	8,565	8,565					
Permits	13,000	13,000					
	$ 37,144	$ 26,384	$ 2,513	$ 1,763	$ 1,234	$ 835	$ 4,415

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, Morocco, Romania, Bulgaria and Turkey. We also lease operations yards and apartments in Turkey.

Our commitments under our permits and contracts require us to complete certain work projects on the relevant permit or license within a specified period of time. Our current commitments under our permits and contracts are due in 2012. If we fail to complete a commitment by the specified deadline, we would lose our rights in such license or permit.

Our commitments pursuant to permits as of December 31, 2011 included commitments to:

Drill one well on License 4174 in Turkey in 2012;

Drill one well on License 4845 in Turkey in 2012;

Drill one well on License 4350 in Turkey in 2012;

Drill one well on License 4861 in Turkey in 2012;

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

- Drill two wells on the South Tuz Golu licenses in Turkey in 2012; and
- Drill two wells on the Sivas Basin licenses in Turkey in 2012.

Our commitments pursuant to contracts with third party license holders as of December 31, 2011 included commitments to:

- Participate in the completion of one well on License 4094 in Turkey in 2012 in accordance with our agreement with Valeura Energy, Ltd.;
- Participate in the drilling of one well on License 3839 in Turkey in 2012 in accordance with our agreement with Valeura Energy, Ltd.;
- Drill one well on License 4325 in Turkey in 2012 in accordance with our agreement with Selsinsan Petrol Maden;
- Drill one well on License 4642 in Turkey in 2012 in accordance with our agreement with Selsinsan Petrol Maden;
- Participate in the completion of two wells on License 3118 in Turkey in 2012 in accordance with our agreement with Aladdin Middle East, Ltd.;
- Drill two wells on License 4288 in Turkey in 2012 in accordance with our agreement with TPAO;
- Drill one well on License 3792 in Turkey in 2012 in accordance with our agreement with TPAO;
- Participate in the drilling of one well on our Thrace Basin licenses in Turkey in 2012 in accordance with our agreement with Valeura Energy, Ltd.; and
- Acquire 200 kilometers of 2D seismic on our Sud Craiova license in Romania in 2012.

17. Contingency

We are involved in litigation with persons who claim ownership of a portion of the surface at the Selmo 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.

Pursuant to the Direct purchase agreement, $10.0 million worth of our common shares would be due if we have not completed certain obligations regarding the drilling the Deventci-R2 well and the coring of the Etropole Shale formation. A provision for this contingency has been accrued of $10 million at December 31, 2011 and we have included the expense in our consolidated statement of operations for the year ended

December 31, 2011.

18. Related party transactions

Debt transactions

On June 28, 2010, we entered into the Dalea Credit Agreement for the purpose of funding the acquisition of all the shares of Amity and Petrogas and for general corporate purposes. Pursuant to the Dalea Credit Agreement, we could request advances from Dalea up to the aggregate principal amount of $100.0 million.

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Notes to Consolidated Financial Statements (Continued)

The advances were denominated in U.S. Dollars. On May 18, 2011, we entered into a first amendment to the Dalea Credit Agreement to extend the maturity date of the credit agreement to December 31, 2011 and to increase the interest rate to match the interest rate payable under the Amended and Restated Credit Facility. On November 7, 2011, we entered into a second amendment to the Dalea Credit Agreement to extend the maturity date to the earlier of (i) March 31, 2012 or (ii) the sale of Viking International and Viking Geophysical. On March 15, 2012, we entered into a third amendment to the Dalea Credit Agreement to extend the maturity date until the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of our oilfield services business or (y) two business days after demand by Dalea. In addition, interest on the Dalea Credit Agreement will cease to accrue from April 1, 2012 until the closing date of the sale of our oilfield services business. If the closing does not occur, the abated interest will be reinstated.

We had borrowed an aggregate of $73.0 million pursuant to the Dalea Credit Agreement as of December 31, 2011. No further borrowings are permitted under the Dalea Credit Agreement.

On June 28, 2010, Viking International entered into the Loan Agreement with Dalea. The purpose of the Loan Agreement was to fund the purchase of equipment and for general corporate purposes. Viking International borrowed an aggregate of $18.5 million, which was secured by (i) the equipment named therein, and (ii) proceeds of the equipment and all accessions to, substitutions and replacements for, and rents, profits and products of, each of the foregoing. We repaid the loan in full on September 30, 2010, and on December 31, 2010, the Loan Agreement was terminated.

Equity transactions

On September 1, 2010, we issued 7,300,000 common share purchase warrants to Dalea pursuant to the Dalea Credit Agreement. The common share purchase warrants are exercisable until September 1, 2013 and have an exercise price of $6.00 per share.

On September 30, 2010, Dalea purchased 1,788,643 common shares at a price of $2.80 per share in the Offering. The common shares sold in the Offering were offered and sold pursuant to our shelf registration statement, which was declared effective on June 18, 2010.

Equipment purchase transactions

On July 27, 2009, Viking International purchased the I-13 drilling rig and associated equipment from Viking Drilling. Viking International paid $1.5 million in cash for the drilling rig and entered into a note payable to Viking Drilling in the amount of $5.9 million. The note was due and payable on August 1, 2010, bore interest at a fixed rate of 10% per annum and was secured by the drilling rig and associated equipment. We paid interest under the note on November 1, 2009 and February 1, 2010. On February 19, 2010, Viking International purchased the I-14 drilling rig and associated equipment from Viking Drilling. Viking International paid $1.5 million in cash for the I-14 drilling rig and entered into an amended and restated note payable to Viking Drilling in the amount of $11.8 million, which was comprised of $5.9 million payable related to the I-14 drilling rig and $5.9 million payable related to the purchase of the I-13 drilling rig in July 2009. Under the terms of the amended and restated note, interest is payable monthly at a floating rate of LIBOR plus 6.25%, and the amended and restated note is due and payable August 1, 2012. The amended and restated note is secured by the I-13 and I-14 drilling rigs and associated equipment. Interest expense for the year ended December 31, 2011 pursuant to the Viking Drilling note was approximately $0.4 million. At December 31, 2011, the outstanding balance under this note was $2.9 million.

Service transactions

Effective May 1, 2008, we entered into a service agreement, as amended (the Service Agreement), with Longfellow Energy, LP (Longfellow), Viking Drilling, MedOil Supply, LLC and Riata Management, LLC (Riata Management). Mr. Mitchell and his wife own 100% of Riata Management. In addition,

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

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. We recorded expenditures for the year ended December 31, 2011 of $14.3 million, for goods and services provided to us under the Service Agreement, of which approximately $0.3 million was payable at December 31, 2011. Payables in the amount of $0.9 million due under the Service Agreement at December 31, 2010 were settled in cash during the first quarter of 2011. Payables in the amount of $0.3 million due under the Service Agreement at December 31, 2011 were settled in cash during the first quarter of 2012. There were no amounts due to us at December 31, 2011.

Effective January 1, 2009, our wholly-owned subsidiary, TransAtlantic Turkey, Ltd., entered into a lease 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 lease agreement, TransAtlantic Turkey, Ltd. paid the New Turkish Lira equivalent of $5,000 per month base rent and up to 45,000 New Turkish Lira per month (approximately $30,000 per month) in operating expense reimbursement. The lease agreement expired December 31, 2009. Effective January 1, 2010, TransAtlantic Turkey, Ltd. and Gundem entered into an accommodation agreement under which it leases 10 rooms at the hotel. Under the accommodation agreement, TransAtlantic Turkey, Ltd. pays the New Turkish Lira equivalent of $10,000 per month. The amounts formerly paid under the lease agreement and paid under the accommodation agreement are included in amounts paid under the Service Agreement. At December 31, 2011, approximately $11,000 was payable by TransAtlantic Turkey, Ltd. to Gundem under this agreement.

On December 15, 2009, Viking International entered into an Agreement for Management Services (Management Services Agreement) with Viking Drilling. Pursuant to the Management Services Agreement, which was amended on August 5, 2010, Viking International agreed to provide management, marketing, storage and personnel services (collectively, the Rig Services) from time to time as requested by Viking Drilling for the operation of certain rigs owned by Viking Drilling that are located in Turkey. Under the terms of the Management Services Agreement, Viking Drilling will pay Viking International for all actual costs and expenses associated with the provision of the Rig Services. In addition, Viking Drilling will pay Viking International a monthly management fee equal to 7% of the total amount invoiced for direct labor costs for employees of Viking International providing Rig Services under the Management Services Agreement. Viking International recorded expenditures for the year ended December 31, 2011 of $0.3 million under the Management Services Agreement, of which approximately $0.1 million was due under the Management Services Agreement at December 31, 2011.

On June 1, 2010, Viking International entered into a lease agreement under which it leased space for storage, maintenance, and staging of material and equipment for oilfield services and services related to oil and natural gas drilling, exploration, development, geological or geophysical activities or oilfield infrastructure at premises owned by Gundem. Under the lease agreement, Viking International pays Gundem the New Turkish Lira equivalent of $25,000 per month from July 2010 through December 2011, $26,000 per month from January 2012 through December 2012, $27,000 per month from January 2013 through December 2013, $28,000 per month from January 2014 through December 2014 and $29,000 per month from January 2015 through December 2017. As of December 31, 2011, approximately $0.3 million has been paid and approximately $25,000 was payable by Viking International to Gundem under this lease agreement.

On August 5, 2010, Viking International entered into an Agreement for Management Services (Maritas Services Agreement) with Maritas A.S. (Maritas). Pursuant to the Maritas Services Agreement, Viking International agreed to provide management, marketing and personnel services (collectively, the Maritas Rig Services) from time to time as requested by Maritas for the operation of a drilling rig owned by MAANBE LLC and located in Iraq. Under the terms of the Maritas Services Agreement, Maritas will pay

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Viking International for all actual costs and expenses associated with the provision of the Maritas Rig Services. In addition, Maritas will pay Viking International a monthly management fee equal to 8% of the total amount invoiced for direct labor costs for employees of Viking International providing Maritas Rig Services under the Maritas Services Agreement. MAANBE LLC is indirectly owned by Mr. Mitchell and his children. Mr. Mitchell indirectly owns 50% of Maritas. For the year ended December 31, 2011, we recorded expenditures of $6.2 million for goods and services provided to us under the Maritas Services Agreement. At December 31, 2011, there was approximately $0.3 million due to us under this agreement.

On September 28, 2010, Viking International entered into an Agreement for Management Services (the VOS Services Agreement) with Viking Petrol Sahasi Hizmetleri A.S. (VOS). VOS is indirectly owned by Mr. Mitchell. Pursuant to the VOS Services Agreement, Viking International agreed to provide management, marketing, storage and personnel services (collectively, the Services) from time to time as requested by VOS for the operation of certain equipment owned by VOS that is located in Turkey. Under the terms of the VOS Services Agreement, VOS will pay Viking International for all actual costs and expenses associated with the provision of the Services. In addition, VOS will pay Viking International a monthly management fee equal to 8% of the total amount invoiced for direct labor costs of employees of Viking International providing Services pursuant to the VOS Services Agreement. For the year ended December 31, 2011, we recorded expenditures of approximately $5.1 million for goods and services provided by us under the VOS Services Agreement, of which $0.6 million was payable at December 31, 2011. At December 31, 2011, there was approximately $0.1 million due to us under this agreement.

The following table summarizes related party accounts receivable and accounts payable as of December 31, 2011 and December 31, 2010:

	2011	2010
	(in thousands)	
Related party accounts receivable:		
Riata Management Service Agreement	$	$ 4
Maritas Services Agreement		3,700
VOS Services Agreement		79
Total related party accounts receivable	$	$ 3,783
Related party accounts payable:		
Riata Management Service Agreement	$ 323	$ 863
Viking Drilling Services Agreement		21
Maritas Services Agreement		85
VOS Services Agreement		
Gundem lease agreement		
Total related party accounts payable	$ 323	$ 969

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TransAtlantic Petroleum Ltd.

Notes to Consolidated Financial Statements (Continued)

The following table summarizes related party accounts receivable held for sale and related party accounts payable held for sale as of December 31, 2011 and December 31, 2010:

	2011	2010
	(in thousands)	
Related party accounts receivable:		
Maritas Services Agreement	$ 251	$
VOS Services Agreement	116	
Total related party accounts receivable held for sale	$ 367	$
Related party accounts payable:		
Viking Drilling Services Agreement	$ 92	$
VOS Services Agreement	617	
Gundem lease agreements	36	
Total related party accounts payable held for sale	$ 745	$

19. Quarterly results of operations (unaudited)

The results of operations by quarter for the years ended December 31, 2011 and 2010 were as follows:

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,[2]
	(in thousands, except per share data)			
For the year ended December 31, 2011:				
Revenues	$ 29,079	$ 31,599	$ 32,038	$ 33,622
Net loss attributable to common shareholders.	(21,155)	(19,815)	(5,477)	(69,396)
Comprehensive loss	(18,856)	(32,341)	(44,130)	(72,964)
Basic and diluted net loss per common share attributable to common shareholders[1]	$ (0.06)	$ (0.06)	$ (0.01)	$ (0.19)
For the year ended December 31, 2010:				
Revenues	$ 11,372	$ 15,800	$ 18,696	$ 24,986
Net loss attributable to common shareholders	(11,340)	(16,434)	(11,774)	(30,198)
Comprehensive gain (loss)	(13,297)	(21,938)	10,346	(52,625)
Basic and diluted net loss per common share attributable to common shareholders[1]	$ (0.04)	$ (0.05)	$ (0.04)	$ (0.09)

(1) The sum of the individual quarterly net loss amounts per share may not agree with year-to-date net 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) The fourth quarter of 2011 includes a $44.7 million impairment charge related to certain of our proved and unproved oil and natural gas properties.

During the fourth quarter of 2011, we identified an error related to our foreign exchange gain (loss) that originated in prior periods and concluded that the error was not material to any of the previously reported periods or to the period in which the error was corrected. The impact of the error resulted in an increase to our net loss of $5.1 million and a decrease to our comprehensive loss of $0.9 million for the three and nine months ended September 30, 2011. This immaterial error was corrected in our third quarter of 2011 results of operations.

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

20. Discontinued Operations

Discontinued operations in Morocco

On June 27, 2011, we decided to discontinue our operations in Morocco. We have transferred our oilfield services equipment from Morocco to Turkey and are in 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 September 30, 2011, we engaged a financial advisor to assist with the sale, transfer or other disposition of our oilfield services business. On March 15, 2012, we entered into a stock purchase agreement with Dalea to sell Viking International and Viking Geophysical for an aggregate purchase price of $164 million, subject to adjustments in certain limited circumstances. We have presented the oilfield services segment operating results as discontinued operations for all periods presented.

The assets and liabilities held for sale of the Moroccan and oilfield services segments at December 31, 2011 are as follows (in thousands):

	Morocco	Oilfield Services	Total Held for Sale
Cash	$ 95	$ 1,090	$ 1,185
Receivables, net		8,098	8,098
Property and equipment, net	1,026	113,497	114,523
Other assets	1,652	2,659	4,311
Total assets held for sale	$ 2,773(1)	$ 125,344	$ 128,117
Accrued expenses and other liabilities	$ 6,154	$ 16,884	$ 23,038
Liabilities held for sale related party		3,676	3,676
Total liabilities held for sale	$ 6,154	$ 20,560	$ 26,714

(1) For the year ended December 31, 2011, we recorded an impairment on our Moroccan assets of approximately $10.8 million.

Operating results of discontinued operations are summarized as follows for the years ended December 31, 2011 and 2010 (in thousands):

	Morocco	Oilfield Services 2011	Total	Morocco	Oilfield Services 2010	Total
Total revenues	$ 217	$ 28,281	$ 28,498	$	$ 14,709	$ 14,709
Total costs and expenses	27,101	39,743	66,844	28,925	23,799	52,724
Total other (expense) income	(178)	2,696	2,518	(124)	1,107	983
Loss before income taxes	$ (27,062)	$ (8,766)	$ (35,828)	$ (29,049)	$ (7,983)	$ (37,032)
Income tax		(4,795)	(4,795)		(1,219)	(1,219)

Loss from discontinued operations	$ (27,062)	$ (13,561)	$ (40,623)	$ (29,049)	$ (9,202)	$ (38,251)

21. Subsequent events

Sale of Oilfield Services Business

On March 15, 2012, we signed a stock purchase agreement to sell our oilfield services business, which is substantially comprised of our wholly owned subsidiaries Viking International and Viking Geophysical

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Notes to Consolidated Financial Statements (Continued)

(collectively, Viking), to Dalea for an aggregate purchase price of $164.0 million, consisting of $152.5 million in cash, subject to a net working capital adjustment, and a $11.5 million promissory note from Dalea. The promissory note will be payable five years from the date of issuance or earlier upon the occurrence of certain specified events, will bear interest at a rate of 3.0% per annum and will be guaranteed by Mr. Mitchell. The sale of Viking is subject to the approval of regulatory authorities, the receipt of equity financing by the buyer and other customary closing conditions.

Contractually, the effective date of the sale of Viking will be April 1, 2012, regardless of when the actual closing occurs. The closing is anticipated to occur during the second quarter of 2012. The purchase price for Viking will be increased by the amount (if any) that the net working capital of Viking is greater than zero and will be decreased by the amount (if any) that the net working capital of Viking is less than zero. We intend to use approximately $4.0 million of the cash consideration to repay (i) the outstanding balance on our amended and restated note payable from Viking International to Viking Drilling and (ii) the outstanding balance of a secured credit agreement entered into by Viking International to fund the purchase of vehicles. We may use the remaining cash proceeds to repay some or all of the outstanding indebtedness under (i) the Amended and Restated Credit Facility and (ii) the Dalea Credit Agreement.

Amendment to Dalea Credit Agreement

In conjunction with the stock purchase agreement, on March 15, 2012, we entered into a third amendment to the Dalea Credit Agreement to extend the maturity date until the earlier of (i) June 30, 2012 or (ii) the later of (x) the closing of the sale of Viking or (y) two business days after demand by Dalea. In addition, interest on the Dalea Credit Agreement will cease to accrue from April 1, 2012 until the closing date of the sale of Viking. If the closing does not occur, the abated interest will be reinstated.

Dalea Credit Facility

On March 15, 2012, we entered into a $15.0 million credit facility with Dalea to provide us with additional liquidity for general corporate purposes until we complete the sale of Viking. If drawn, loans under the credit facility will accrue interest at a rate of three month LIBOR plus 5.5% per annum. Any proceeds received by us or any subsidiary from any debt financings (subject to certain specified exceptions) or from the sale of Viking, net of reasonable transaction and financing costs, must be used to repay amounts outstanding under the credit facility. If drawn, any outstanding borrowings must be repaid upon the earlier of (i) July 1, 2012 or (ii) the sale of Viking.

Poland Services Agreement

On March 15, 2012, Viking Geophysical entered into a Management Services Agreement (the Poland Services Agreement) with VOS. VOS is indirectly owned by Mr. Mitchell. Pursuant to the Poland Services Agreement, Viking Geophysical agreed to provide management and personnel services (collectively, the VGS Services) from time to time as necessary to enable certain equipment owned by VOS to be used in Poland in accordance with a certain Master Services Agreement among Viking Geophysical, VOS and GX Technology Corporation and its affiliates (the GXT Agreement). Under the GXT Agreement, VOS and Viking Geophysical have each agreed to provide seismic data acquisition services to GXT Technology Corporation and its affiliates in Poland (the Poland Project). The Poland Services Agreement will terminate upon termination of the GXT Agreement.

Under the terms of the Poland Services Agreement, VOS will pay Viking Geophysical for all actual costs and expenses associated with the provision of the VGS Services. In addition, VOS will pay Viking Geophysical a monthly management fee equal to 8% of the total amount invoiced for direct labor costs of employees of Viking Geophysical providing VGS Services pursuant to the Poland Services Agreement. In

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Notes to Consolidated Financial Statements (Continued)

addition, the Poland Services Agreement provides that (i) all revenues and expenses generated from providing seismic data acquisition services in connection with the Poland Project will be divided evenly between VOS and Viking Geophysical, except during the period that either party has the sole acquisition crew operating in Poland and (ii) all revenues and royalties generated for the account of VOS and Viking Geophysical by the sale of the Poland Project seismic data will be divided evenly between VOS and Viking Geophysical.

22. Supplemental oil and natural gas reserves and standardized measure information (unaudited)

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.

At December 31, 2011, substantially all of our proved reserves were located in Turkey.

The 12-month average prices of oil and natural gas for 2011, 2010 and 2009 used to estimate reserves are shown in the table below.

	12-Month Average Price	
	Oil	Gas
2011	$ 108.00	$ 7.18
2010	$ 79.00	$ 7.77
2009	$ 95.72	$ 8.91

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 reserve quantities

	Oil (Mbls)	Natural Gas (Mmcf)	Mboe
Total proved reserves			
December 31, 2008			
Acquisitions	9,253	784	9,384
Extensions and discoveries		5,948	991
Revisions of previous estimates	1,584	607	1,685
Production	(411)		(411)
December 31, 2009	10,426	7,339	11,649
Acquisitions	1	13,987	2,332
Extensions and discoveries		1,923	321
Revisions of previous estimates	3,199	883	3,346
Production	(690)	(1,707)	(975)
December 31, 2010	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)
Production	(891)	(4,657)	(1,667)
December 31, 2011	11,215	13,223	13,419

TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

	Oil (Mbls)	Natural Gas (Mmcf)	Mboe
Proved developed reserves			
December 31, 2009			
Proved developed producing	3,777		3,777
Proved developed non-producing	1,872	4,787	2,670
Total	5,649	4,787	6,447
December 31, 2010			
Proved developed producing	4,775	7,820	6,078
Proved developed non-producing	813	8,741	2,270
Total	5,588	16,561	8,348
December 31, 2011			
Proved developed producing	4,284	6,564	5,378
Proved developed non-producing	1,089	3,956	1,748
Total	5,373	10,520	7,126
Proved developed reserves			
As of December 31, 2009	5,649	4,787	6,447
As of December 31, 2010	5,588	16,561	8,348
As of December 31, 2011	5,373	10,520	7,126
Proved undeveloped reserves			
As of December 31, 2009	4,777	2,552	5,202
As of December 31, 2010	7,348	5,865	8,326
As of December 31, 2011	5,842	2,703	6,293

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, 2011, 2010 and 2009 are shown in the table below.

	2011	2010 (in thousands)	2009
Future cash inflows	$ 1,306,844	$ 1,197,740	$ 700,003
Future production costs	(246,566)	(300,347)	(161,173)
Future development costs	(63,805)	(80,255)	(46,234)
Future income tax expense	(171,592)	(143,000)	(94,468)
Future net cash flows	824,881	674,138	398,128
10% annual discount for estimated timing of cash flows	(293,084)	(235,771)	(148,119)
Standardized measure of discounted future net cash flows related to proved reserves	$ 531,797	$ 438,367	$ 250,009

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

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, 2011, 2010 and 2009. We did not have any proved reserves as of January 1, 2009.

	2011	2010 (in thousands)	2009
Standardized measure, January 1,	$ 438,367	$ 250,009	$
Net change in sales and transfer prices and in production (lifting) costs related to future production	244,980	53,003	137,280
Changes in future estimated development costs	(34,401)	(63,040)	(10,019)
Sales and transfers of oil and natural gas during the period	(108,915)	(50,033)	(17,803)
Net change due to extensions and discoveries	5,684	11,321	29,090
Net change due to purchases of minerals in place	48,017	79,478	83,586
Net change due to revisions in quantity estimates	(134,997)	121,101	49,450
Previously estimated development costs incurred during the period	54,943	29,659	6,361
Accretion of discount	52,254	31,249	10,449
Other	(15,604)	7,471	95
Net change in income taxes	(18,531)	(31,851)	(38,480)
Standardized measure, December 31,	$ 531,797	$ 438,367	$ 250,009

Capitalized costs related to oil and natural gas producing activities

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

	Turkey	Other (in thousands)	Total
As of December 31, 2011			
Oil and natural gas properties			
Proved	$ 172,886	$ 1,691	$ 174,577
Unproved	70,180		70,180
Total oil and natural gas properties	243,066	1,691	244,757
Less accumulated depletion	(44,870)	(457)	(45,327)
Net oil and natural gas properties capitalized costs	$ 198,196	$ 1,234	$ 199,430
As of December 31, 2010			
Oil and natural gas properties			
Proved	$ 150,407	$	$ 150,407
Unproved	73,662	6,505	80,167
Total oil and natural gas properties	224,069	6,505	230,574
Less accumulated depletion	(14,360)		(14,360)

Net oil and natural gas properties capitalized costs	$ 209,709	$ 6,505	$ 216,214

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TRANSATLANTIC PETROLEUM LTD.

Notes to Consolidated Financial Statements (Continued)

	Turkey	Other (in thousands)	Total
As of December 31, 2009			
Oil and natural gas properties			
Proved	$ 66,313	$	$ 66,313
Unproved	3,193	9,170	12,363
Total oil and natural gas properties	69,506	9,170	78,676
Less accumulated depletion	(2,483)		(2,483)
Net oil and natural gas properties capitalized costs	$ 67,023	$ 9,170	$ 76,193

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, 2011, 2010 and 2009 are summarized as follows:

	Turkey	Other (in thousands)	Total
For the year ended December 31, 2011			
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
For the year ended December 31, 2010			
Acquisitions of properties			
Proved	$ 53,997	$	$ 53,997
Unproved	49,017		49,017
Exploration	31,452	28,377	59,829
Development	37,198		37,198
Total costs incurred	$ 171,664	$ 28,377	$ 200,041
For the year ended December 31, 2009			
Acquisitions of properties			
Proved	$ 66,313	$	$ 66,313
Unproved	3,193	8,665	11,858
Exploration	4,944	19,847	24,791
Development	7,234	3,304	10,538
Total costs incurred	$ 81,684	$ 31,816	$ 113,500

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TransAtlantic Petroleum Ltd.

Notes to Consolidated Financial Statements (Continued)

Results of operations for oil and natural gas producing activities (unaudited)

Our results of operations from oil and natural gas producing activities for each of the years 2011, 2010 and 2009 are shown in the following table:

	Turkey	Other (in thousands)	Total
For the year ended December 31, 2011			
Revenues	$ 123,636	$ 549	$ 124,185
Expenses:			
Production costs	16,943	991	17,934
Exploration, abandonment and impairment	36,290	23,944	60,234
Seismic and other exploration	7,753	1,874	9,627
Depreciation, depletion and amortization expenses	41,036	619	41,655
Total expenses	102,022	27,428	129,450
Income (loss) before income taxes	21,614	(26,879)	(5,265)
Income tax benefit	3,105		3,105
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 24,719	$ (26,879)	$ (2,160)
For the year ended December 31, 2010			
Revenues	$ 69,657	$ 182	$ 69,839
Expenses:			
Production costs	20,201	85	20,286
Exploration, abandonment and impairment	7,425	5,266	12,691
Seismic and other exploration	9,539	2,585	12,124
Depreciation, depletion and amortization expenses	18,044	139	18,183
Total expenses	55,209	8,075	63,284
Income (loss) before income taxes	14,448	(7,893)	6,555
Income tax benefit	1,104		1,104
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 15,552	$ (7,893)	$ 7,659
For the year ended December 31, 2009			
Revenues	$ 27,546	$ 135	$ 27,681
Expenses:			
Production costs	9,814	245	10,059
Exploration, abandonment and impairment	191	8,891	9,082
Seismic and other exploration	4,948	561	5,509
Depreciation, depletion and amortization expenses	3,094	148	3,242
Total expenses	18,047	9,845	27,892

Income (loss) before income taxes	9,499	(9,710)	(211)
Provision for income taxes	(1,079)		(1,079)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 8,420	$ (9,710)	$ (1,290)

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