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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, 2015

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 (State or other jurisdiction of incorporation or organization)	**None** (I.R.S. Employer Identification No.)
16803 Dallas Parkway **Addison, Texas** (Address of principal executive offices)	**75001** (Zip Code)

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

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 $0.10	**NYSE MKT**

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 x

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 x

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

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 x 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	x
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 x

The aggregate market value of common shares, par value $0.10 per share, held by non-affiliates of the registrant, based on the last sale price of the common shares on June 30, 2015 (the last business day of the registrant's most recently completed second fiscal quarter), was approximately $22.1 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 29, 2016, there were 41,106,194 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 2016 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.

TRANSATLANTIC PETROLEUM LTD.
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2015
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Forward-Looking Statements

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

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements, including the factors discussed under Item 1A. Risk Factors in this Annual Report on Form 10-K. Such factors include, but are not limited to, the following: our ability to access sufficient capital to fund our operations, sell assets, repay our borrowing base deficiency, continue as a going concern and restructure our debt; fluctuations in and volatility of the market prices for oil and natural gas products; the ability to produce and transport oil and natural gas; the results of exploration and development drilling and related activities; global economic conditions, particularly in the countries in which we carry on business, especially economic slowdowns; actions by governmental authorities including increases in taxes, legislative and regulatory initiatives related to fracture stimulation activities, changes in environmental and other regulations, and renegotiations of contracts; political uncertainty, including actions by insurgent groups or other conflicts; the negotiation and closing of material contracts or sale of assets; 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; asset sales; negotiations with creditors; the allocation of capital expenditures to exploration and development activities; sources of funding for our capital expenditure programs or operations; drilling of new wells; demand for oil and natural gas products; expenditures and allowances relating to environmental matters; dates by which certain areas will be developed or will come on-stream; expected finding and development costs; future production rates; ultimate recoverability of reserves, including the ability to convert probable and possible reserves to proved reserves; dates by which transactions are expected to close; future cash flows, uses of cash flows, collectability of receivables and availability of trade credit; expected operating costs; changes in any of the foregoing and other statements using forward-looking terminology are forward-looking statements, and there can be no assurance that the expectations conveyed by such forward-looking statements will, in fact, be realized.

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

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

Glossary of Selected Oil and Natural Gas Terms

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

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

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

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

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

Bbl/d. Barrels of oil per day.

Bcf. One billion cubic feet of natural gas.

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

Boepd. Barrels of oil equivalent per day.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mbbl. One thousand stock tank barrels.

Mboe. One thousand barrels of oil equivalent.

Mboepd. One thousand barrels of oil equivalent per day.

Mcf. One thousand cubic feet of natural gas.

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

Mmbbl. One million stock tank barrels.

Mmboe. One million barrels of oil equivalent.

Mmcf. One million cubic feet of natural gas.

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

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

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

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

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

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

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

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.

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.

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

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

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

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, 2015, 2014 and 2013 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.

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

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

PART I

Item 1. Business

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

Our Business

We are an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established, yet underexplored, petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2015, we held interests in approximately 880,000 and 567,000 net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria, respectively. As of March 29, 2016, approximately 36% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, the chairman of our board of directors and our chief executive officer.

Based on the reserves report prepared by DeGolyer and MacNaughton, independent petroleum engineers, our estimated proved reserves at December 31, 2015 in Turkey were approximately 13,457 Mboe, of which 80.4% was oil. Of these estimated proved reserves, 52.5% were proved developed reserves. As of December 31, 2015, the PV-10 and Standardized Measure, as calculated by the Company, of our proved reserves in Turkey were $222.5 million and $199.2 million, respectively. See “Item 2. Properties—Value of Proved Reserves” for a reconciliation of PV-10 to the Standardized Measure.

Recent Developments

Convertible Promissory Note. On December 30, 2015, we entered into a $5.0 million draw down convertible promissory note (the “Note”) with ANBE Holdings, L.P. (“ANBE”), an entity owned by Mr. Mitchell’s children and controlled by an entity managed by Mr. Mitchell and his wife. The Note bears interest at a rate of 13.0% per annum and matures on June 30, 2016. On December 30, 2015, we borrowed $3.6 million under the Note (the “Initial Advance”). The conversion price of the Initial Advance is $1.3755 per share. The Initial Advance was used for general corporate purposes. We can request subsequent advances of $500,000 under the Note prior to June 15, 2016. The Note is an unsecured obligation of the Company and is structurally subordinated to all indebtedness of our subsidiaries.

Senior Credit Facility Borrowing Base Deficiency. Due to the significant decline in Brent crude oil prices during 2015, the borrowing base under the Company’s senior credit facility (the “Senior Credit Facility”) with BNP Paribas (Suisse) SA (“BNP Paribas”) and the International Finance Corporation (“IFC”) was decreased to $16.6 million effective December 30, 2015. The decline in the borrowing base resulted in a $15.5 million borrowing base deficiency under the Senior Credit Facility as of December 30, 2015.

On December 30, 2015, the lenders granted us a waiver of certain defaults under the Senior Credit Facility that existed as of December 30, 2015, including, among other things, the borrowing base deficiency. The waiver is conditioned upon, among other things, no borrowing base deficiency existing as of March 31, 2016.

As of December 31, 2015, the Company had $32.1 million outstanding under the Senior Credit Facility and no availability and was not in compliance with the current ratio financial covenant in the Senior Credit Facility. As of March 30, 2016, the borrowing base deficiency was $14.2 million.

We have negotiated a preliminary waiver of the existing defaults under the Senior Credit Facility and an extension of the borrowing base deficiency repayment obligation until at least September 30, 2016. This preliminary waiver and extension is subject to the approval of the lenders’ respective credit committees. The lenders have advised us that they will seek credit committee approval of the preliminary waiver and extension in early April 2016. We cannot guarantee that this waiver and extension will be approved by our lenders. Because we are currently in default under the Senior Credit Facility and will be unable to repay the borrowing base deficiency by March 31, 2016, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, could foreclose against the assets securing their borrowings, and we could be forced into bankruptcy or liquidation. In addition, a payment default under the Senior Credit Facility could result in a cross default under our 13.0% convertible notes due 2017 (“Convertible Notes”).

Sale of Albania Operations. In February 2016, we sold all of the outstanding equity in our wholly-owned subsidiary, Stream Oil & Gas Ltd. (“Stream”), to GBC Oil Company Ltd. (“GBC Oil”) in exchange for (i) the future payment of $2.3 million to Raiffeisen

Bank Sh.A ("Raiffeisen") to pay down a term loan facility (the "Term Loan Facility") dated as of September 17, 2014 between Stream's wholly-owned subsidiary, TransAtlantic Albania Ltd. ("TransAtlantic Albania"), and Raiffeisen, and (ii) the assumption of $29.2 million of liabilities owed by Stream, consisting of $23.1 million of accounts payable and accrued liabilities and $6.1 million of debt. TransAtlantic Albania owns all of our former Albanian assets and operations. In addition, GBC Oil issued us a warrant pursuant to which we have the option to acquire up to 25% of the fully diluted equity interests in TransAtlantic Albania for nominal consideration at any time on or before March 1, 2019. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and $12.9 million of associated liabilities (the "Delvina Gas Liabilities") to Delvina Gas Company, Ltd. ("Delvina Gas"), our newly formed, wholly-owned subsidiary, to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. In addition, we agreed to indemnify GBC Oil and Stream for the Delvina Gas Liabilities. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas.

Our Properties and Operations

Summary of Geographic Areas of Operations

The following table shows net reserves information as of December 31, 2015:

	Proved Developed Reserves (Mboe)	Proved Undeveloped Reserves (Mboe)	Total Proved Reserves (Mboe)	Probable Reserves (Mboe)	Possible Reserves (Mboe)
Turkey	7,061	6,396	13,457	14,307	22,995
Albania(1)	4,241	938	5,179	15,439	13,601

(1) As of December 31, 2015, we have classified our Albanian assets and liabilities as held for sale and presented the operating results within discontinued operations for all periods presented in our consolidated financial statements in this Annual Report on Form 10-K. In February 2016, we sold all of the outstanding equity in Stream to GBC Oil. Stream's wholly owned subsidiary, TransAtlantic Albania, owns all of our former Albanian assets and operations. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and the Delvina Gas Liabilities to Delvina Gas to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas.

Turkey

As of December 31, 2015, we held interests in 18 onshore and offshore exploration licenses and 25 onshore production leases covering a total of 1.4 million gross acres (880,000 net acres) in Turkey. As of December 31, 2015, we had total net proved reserves of 10,815 Mbbl of oil and 15,847 Mmcf of natural gas, net probable reserves of 10,931 Mbbl of oil and 20,253 Mmcf of natural gas and net possible reserves of 11,205 Mbbl of oil and 70,739 Mmcf of natural gas in Turkey. During 2015, our average wellhead production was approximately 5,128 net Boepd of oil and natural gas in Turkey. The following summarizes our core producing properties in Turkey:

Southeastern Turkey. During 2015, substantially all of our oil production was concentrated in southeastern Turkey, primarily in the Arpatepe, Bahar, Goksu and Selmo oil fields. These fields are located southwest of the Turkish portion of the Zagros fold belt. The Zagros fold belt includes prolific oil trends that extend from Iran and Iraq into Turkey.

We hold a 100% working interest in the Selmo production lease, which expires in June 2025. 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. We expanded our waterflood program and executed several low-cost production optimizations in the Selmo field in 2015. We believe secondary recovery will continue to increase production recovery from the field. For 2015, our net wellhead production of crude oil from the Selmo field was 934,777 Bbls at an average rate of approximately 2,561 Bbl/d. 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 oil field, which is transported by truck to their neighboring facilities. At December 31, 2015, we had 69 gross and net producing wells in the Selmo oil field.

We hold a 100% working interest in each of our three Molla exploration licenses, which contain the Goksu and Bahar oil fields. In the Goksu field, we are primarily targeting the Mardin formation, and in the Bahar field, we are primarily targeting the Bedinan and

Hazro formations. In 2015, we drilled three wells, completed one well, and completed one re-entry well as a water injection well in the Bahar field. For 2015, our wellhead production of crude oil from the Molla exploration licenses was 491,090 Bbls at an average rate of approximately 1,345 Bbl/d. At December 31, 2015, we had six gross and net producing wells on the Molla exploration licenses.

We hold a 50% working interest in our Arpatepe production lease and exploration license. For 2015, our wellhead production of crude oil from the Arpatepe field was 51,527 Bbls at an average rate of approximately 141 Bbl/d. At December 31, 2015, we had seven gross (3.5 net) producing wells on the Arpatepe production lease. We became the operator of the Arpatepe production lease in December 2015.

Northwestern Turkey. Substantially all of our natural gas production is concentrated in the Thrace Basin, which is one of Turkey's most productive onshore natural gas regions. It is located in northwestern Turkey near Istanbul.

Bulgaria

As of December 31, 2015, we held interests in one onshore exploration license and one onshore production concession covering a total of 567,106 acres in Bulgaria. During 2015, we had no production in Bulgaria. At December 31, 2015, we had no reserves in Bulgaria.

Albania

In November 2015, we launched a marketing process for the sale of all of our oil and natural gas assets and operations in Albania. Accordingly, as of December 31, 2015, we have classified our Albanian segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented in our consolidated financial statements included in this Annual Report on Form 10-K.

In February 2016, we sold all of the outstanding equity in Stream to GBC Oil. Stream's wholly owned subsidiary, TransAtlantic Albania, owns all of our former Albanian assets and operations. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and the Delvina Gas Liabilities to Delvina Gas to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas. See "—Recent Developments."

Current Operations

As of March 24, 2016, our net wellhead production in Turkey was an aggregate of approximately 3,750 Bbl/d, primarily from the Selmo production lease, Arpatepe production lease and Molla exploration licenses, and approximately 5.7 Mmcf/d of natural gas, primarily from our various Thrace Basin production leases and exploration licenses.

In January 2016, we completed the Bahar-7 and Bahar-9 wells in the Bedinan formation. The initial production rate on the Bahar-7 well was approximately 570 Bbl/d of oil and 300 Mmcf/d of natural gas. The Bahar-9 well tested both oil and water and was temporarily plugged back. In February 2016, we completed the Hazro formation in the Bahar-9 well, which had an initial production rate of approximately 100 Bbl/d of oil. We expect to commingle producing zones when our electrification and our artificial lift program is completed later in 2016. We are continuing our well optimization work program in the Selmo oil field and have been able to stem natural decline as a result.

Planned Operations

We expect our net field capital expenditures for 2016 to range between $5.0 million and $15.0 million. Given the market conditions and our limited access to capital, our 2016 development plan may be limited to drilling obligation wells and performing low cost, high return well optimizations. We expect net field capital expenditures during 2016 to include approximately $5.0 million of drilling and completion expense for gross obligation wells to hold our most promising licenses in Turkey. We expect cash on hand and cash flow from operations will be sufficient to fund our 2016 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2016 capital expenditure budget is subject to change.

Principal Markets

In accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 280, *Segment Reporting* ("ASC 280"), we had three reportable geographic segments during 2015: Turkey, Albania and Bulgaria. For financial information about our operating segments and geographic areas, refer to "Note 12—Segment information" to our consolidated financial statements.

Customers

Oil. During 2015, 56.6% of our oil production was concentrated in the Selmo field in Turkey. TUPRAS purchases the majority of our oil production. During 2015, we sold $63.0 million of oil to TUPRAS, representing approximately 74.0% of our total revenues. We sell all of our southeastern Turkey 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. No other purchasers of our oil accounted for more than 10% of our total revenues.

Natural Gas. During 2015, no purchasers of our natural gas accounted for 10% or more of our total revenues.

Competition

We operate in the highly competitive areas of oil and natural gas exploration, development, production and acquisition with a 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 and acquiring desirable producing properties or new leases for future exploration.

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

Fracture Stimulation Program

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

For unconventional reservoirs, including the Mezardere formation in the Thrace Basin, a typical fracture stimulation consists of injecting between 20,000 and 100,000 gallons of fluid that contain between 10,000 and 150,000 pounds of sand. Fluids vary depending on formation and treatment objective but, in general, are either slickwater (fresh water with salt and friction reducer) or a gelled fluid containing organic polymers with a 4% potassium chloride solution and required breakers. Fracture stimulations in Molla are conducted in a low permeability reservoir. These stimulations generally consist of injecting between 20,000 and 100,000 gallons of fluid that contain between 10,000 and 100,000 pounds of sand. Fluids are generally a mixture of slickwater and gells, which is typical in stimulation. The size of fracture stimulation treatments is dependent on net pay thickness and the proximity of the hydrocarbon zones of interest to water bearing zones.

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

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

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

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

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

Governmental Regulations

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

- the risk of expropriation, nationalization, war, revolution, political instability, border disputes, renegotiation or modification of existing contracts, and import, export and transportation regulations and tariffs;
- laws of foreign governments affecting our ability to fracture stimulate oil or natural gas wells, such as the legislation enacted in Bulgaria in January 2012;
- the risk of not being able to procure residency and work permits for our expatriate personnel;
- taxation policies, including royalty and tax increases and retroactive tax claims;
- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over international operations;
- laws and policies of the United States affecting foreign trade, taxation and investment, including anti-bribery and anti-corruption laws;
- the possibility of being subjected to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- the possibility of restrictions on repatriation of earnings or capital from foreign countries.

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

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

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

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

Such laws and regulations not only expose us to liability for our own negligence, but may also expose us to liability for the conduct of others or for our actions that were in compliance with all applicable laws at the time those actions were taken. We may incur significant costs as a result of environmental accidents, such as oil spills, natural gas leaks, ruptures, or discharges of hazardous materials into the environment, including clean-up costs and fines or penalties. Additionally, we may incur significant costs in order to comply with environmental laws and regulations and may be forced to pay fines or penalties if we do not comply.

Insurance

We currently carry general liability insurance and excess liability insurance, including pollution insurance, with a combined annual limit of $22.0 million per occurrence and $24.0 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. Our control of well insurance has a per occurrence and combined single limit of $15.0 million and is subject to deductibles ranging from $150,000 to $500,000 per occurrence. We will continue to monitor our insurance coverage and will maintain appropriate levels of insurance to satisfy applicable regulations, as well as maintain levels of insurance appropriate for prudent operations within the industry in which we operate.

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

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

Bermuda Tax Exemption

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

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

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

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

Employees

As of December 31, 2015, we employed 402 people in Albania, 178 people in Turkey, 39 people in Addison, Texas and three people in Bulgaria. Approximately 38 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with the Petroleum, Chemical and Rubber Workers Union of Turkey (“PETROL-IS”). Approximately 36 of our employees at another of our subsidiaries operating in Turkey were represented by a separate collective bargaining agreement with 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.

Executive Officers of the Registrant

The following table and text sets forth certain information with respect to our executive officers as of March 1, 2016:

Name	Age	Positions
N. Malone Mitchell 3rd	54	Chairman and Chief Executive Officer
Todd C. Dutton	62	President
Wil F. Saqueton	46	Vice President and Chief Financial Officer
Chad D. Burkhardt	41	Vice President, General Counsel and Corporate Secretary
Harold “Lee” Muncy	63	Vice President of Geosciences

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.

Todd C. Dutton has served as our president since May 2014. Mr. Dutton has served as president of Longfellow Energy, LP ("Longfellow"), a Dallas, Texas-based independent oil and natural gas exploration and production company owned by the Company's chairman and chief executive officer, N. Malone Mitchell 3rd and his family, since January 2007, where his primary responsibility is to originate and develop oil and natural gas projects. He brings 39 years of experience in the oil and natural gas industry, focusing on exploration, acquisitions and property evaluation. He has served in various supervisory and management roles at Texas Pacific Oil Company, Coquina Oil Corporation, BEREXCO INC. and Riata Energy, Inc. Mr. Dutton earned a B.B.A. in Petroleum Land Management from the University of Oklahoma.

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

Chad D. Burkhardt has served as the Company's vice president, general counsel and corporate secretary since August 2015. From 2008 until August 2015, Mr. Burkhardt served as partner in the corporate department of Baker Botts L.L.P., where he advised clients on various corporate transactions including corporate securities offerings, mergers and acquisitions and various public company filings. Mr. Burkhardt brings significant cross-border and international transaction experience from a variety of industries ranging from oil and gas exploration, midstream, and oil field services to high-tech and start-up transactions. Mr. Burkhardt is a graduate of Duke University School of Law.

Harold "Lee" Muncy has served as the Company's vice president of geosciences since June 2014. Mr. Muncy previously served as vice president, exploration for the Bass Companies, a group of Fort Worth, Texas-based independent oil and natural gas exploration and production companies, where he worked from 2000 to 2012. He brings more than 35 years of geological experience in the oil and natural gas industry, where he has focused on exploration, exploitation and worldwide transactions. He began his career as a geologist with Mobil Oil Corporation and served as exploration manager for Fina Oil & Chemical Company and vice president of exploration and land for TransTexas Gas Corp. Mr. Muncy earned a B.S. and an M.S. in Geology & Mineralogy from The Ohio State University.

Item 1A. Risk Factors

Risks Related to Our Business

We are currently in default under our Senior Credit Facility, and our Senior Credit Facility lenders could foreclose against the assets securing their borrowings, and we could be forced into bankruptcy or liquidation.

As of December 31, 2015, we had $32.1 million outstanding under the Senior Credit Facility and no availability and were not in compliance with the current ratio financial covenant in the Senior Credit Facility.

In addition, we had a borrowing base deficiency as of December 30, 2015. On December 30, 2015, the lenders granted us a waiver of certain defaults under the Senior Credit Facility that existed as of December 30, 2015, including, among other things, the borrowing base deficiency. The waiver is conditioned upon, among other things, no borrowing base deficiency existing as of March 31, 2016. As of March 30, 2016, the borrowing base deficiency was $14.2 million. We will not be able to repay the borrowing base deficiency by March 31, 2016. A payment default under the Senior Credit Facility could result in a cross default under the Convertible Notes.

As a result of our current rational financial covenant default under the Senior Credit Facility or our future failure to repay the borrowing base deficiency on or before March 31, 2016, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, could foreclose against the assets securing their borrowings, and we could be forced into bankruptcy or liquidation.

The prevailing commodity price environment may require us to sell certain assets, restructure our debt, raise additional capital or seek bankruptcy protection.

Our current liquidity position is very constrained. Even if we obtain the funds to repay our borrowing base deficiency, we would need some form of debt restructuring, capital raising effort or asset sale in order to fund our operations and meet our substantial debt service obligations of approximately $41.9 million in 2016 and $55.0 million in 2017. Our management is actively pursuing improving our working capital position and/or reducing our future debt service obligations in order to remain a going concern for the foreseeable future. If we are unable to restructure our outstanding debt, obtain additional debt or equity financing, or raise adequate proceeds from sales of assets, we may not be able to make payments on our indebtedness, our secured lenders could foreclose against the assets securing their borrowings or freeze our accounts, and we may find it necessary to file a voluntary petition for reorganization relief in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure.

There is substantial doubt about our ability to continue as a going concern.

We incurred a net loss from continuing operations for the fiscal year ended December 31, 2015 of $26.7 million. In addition, we had a working capital deficit (excluding assets and liabilities held for sale) of $30.1 million at December 31, 2015. We continue to experience decreased liquidity as a result of the decline in oil and natural gas commodity prices and other factors discussed below. As of March 30, 2016, we had a borrowing base deficiency of $14.2 million under the Senior Credit Facility that must be repaid by March 31, 2016 and were not in compliance with the current ratio financial covenant as of December 31, 2015. We will not be able to repay the borrowing base deficiency by March 31, 2016. Consequently, we have undertaken marketing effects with respect to certain assets to fund our operations and debt obligations. However, proceeds from these potential asset sales may not provide sufficient liquidity to fund operations and debt obligations for the next twelve months. These factors raise substantial doubt about our ability to continue as a going concern. The consolidated financial statements included in this report do not include any adjustments relating to the recoverability and classification of recorded asset amounts or amounts of liabilities that might result from the outcome of this uncertainty.

Oil prices have decreased substantially from historic highs and may remain depressed for the foreseeable future. The decline in oil prices has materially and adversely affected our cash generated from operations, results of operations, financial position, our ability to repay our debt, and the trading price of our common shares.

Since the second half of 2014, oil prices have declined significantly. As a result of the decrease in oil prices, we incurred an impairment of proved oil and natural gas properties and exploratory well costs of $16.0 million, not including an impairment on goodwill of $5.5 million, during the year ended December 31, 2015, which reduced earnings and shareholders’ equity. In addition, as a result of decreased oil and natural gas prices, our borrowing base under the Senior Credit Facility was reduced, which resulted in a borrowing base deficiency of $14.2 million as of March 30, 2016.

We may incur additional impairments of our oil and natural gas properties and experience continued constrained liquidity if prices do not increase. The possibility and amounts of any future impairments or losses are difficult to predict, and will depend, in part, upon future oil and natural gas prices. If prices for oil continue to remain depressed for lengthy periods, we may be required to write down the value of our oil and natural gas properties, and some of our current projects may no longer be economically viable. In addition, sustained low prices for oil will negatively impact the value of our estimated proved reserves and reduce the amounts of cash we would otherwise have available to fund the drilling of obligation wells, pay expenses and service our indebtedness. If we are unable to fund the drilling of some or all of our obligation wells, we could lose some or all of our licenses.

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

We have incurred substantial losses in prior years. During 2015, we generated a net loss from continuing operations of $26.7 million. We will need to generate and sustain increased revenue levels in future periods in order to become consistently profitable, and even if we do, we may not be able to maintain or increase our level of profitability. We may incur losses in the future for a number of reasons, including the risks described herein, unforeseen expenses, difficulties, complications and delays, and other unknown risks.

Our Senior Credit Facility contains various restrictive covenants that limit our management's discretion in the operation of our business and could 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 Senior Credit Facility may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Our Senior Credit Facility contains various covenants that restrict our ability to, among other things:

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

In addition, the Senior 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 Senior Credit Facility and could result in an event of default under the Senior Credit Facility. As of December 31, 2015, we were not in compliance with the current ratio financial covenant in the Senior Credit Facility, which is an event of default.

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

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

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

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

The majority of our oil is sold to one customer, and the loss of this customer could have a material adverse impact on our results of operations.

TUPRAS purchases all of our oil production from Turkey, representing 74.0% of our total revenues in 2015. If TUPRAS reduces its oil purchases or fails to purchase our oil production, or there is a material non-payment, our results of operations could be materially and adversely affected. TUPRAS may be subject to its own operating risks that could increase the risk that it could default on its obligations to us. Under Turkish law, TUPRAS is obligated to purchase all of our oil production in Turkey, and we are prohibited from selling any of our oil produced in Turkey to any other customer. Pursuant to a purchase and sale agreement with TUPRAS, the price of oil delivered to TUPRAS is determined under the Petroleum Market Law No. 5015 under the laws of the Republic of Turkey. Changes to Turkish law could adversely affect our business and results of operations.

A significant failure of our computer systems may increase our operating costs or otherwise adversely affect our business.

We depend upon our computer systems to perform accounting and administrative functions as well as manage other aspects of our operations. We maintain normal backup polices with respect to our computer systems and networks. Nevertheless, our computer systems and networks are subject to risks that may cause interruptions in service, including, but not limited to, security breaches, physical damage, power loss, software defects, hacking attempts, computer viruses and malware, lost data and programming and/or human errors. Significant interruptions in service, security breaches or lost data may have a material adverse effect on our business, financial condition or results of operations.

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

At December 31, 2015, of our total net undeveloped acreage, 25.0% and 7.0% will expire during 2016 and 2017, respectively, unless we are able to extend the permits or licenses covering this acreage or commence production on this acreage and convert the permits or licenses into production leases or concessions. If our permits or licenses expire, we will lose our right to explore and develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control. Such factors include drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. In addition, if our liquidity continues to be constrained and we are not able to access additional capital, we may be unable to fund the drilling of some or all of our obligation wells, and we could lose some or all of our licenses.

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

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

- the risk of, and disruptions due to, expropriation, nationalization, war, revolution, election outcomes, economic instability, political instability, or border disputes;
- the uncertainty of local contractual terms, renegotiation or modification of existing contracts and enforcement of contractual terms in disputes before local courts;
- the risk of import, export and transportation regulations and tariffs, including boycotts and embargoes;
- the risk of not being able to procure residency and work permits for our expatriate personnel;
- the requirements or regulations imposed by local governments upon local suppliers or subcontractors, or being imposed in an unexpected and rapid manner;

- taxation and revenue policies, including royalty and tax increases, retroactive tax claims and the imposition of unexpected taxes or other payments on revenues;
- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over foreign operations;
- laws and policies of the United States, including the U.S. Foreign Corrupt Practices Act, ("FCPA") and of the other countries in which we operate affecting foreign trade, taxation and investment, including anti-bribery and anti-corruption laws;
- our internal control policies may not protect us from reckless and criminal acts committed by our employees or agents, including violations or alleged violations of the FCPA;
- the possibility of being subjected to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- the possibility of restrictions on repatriation of earnings or capital from foreign countries.

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

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

During 2015, we derived 56.6% of our oil production from the Selmo oil field in southeastern Turkey. Historically, the southeastern area of Turkey and nearby countries such as Iran, Iraq and Syria have experienced political, social, security and economic problems, terrorist attacks, insurgencies, war and civil unrest. Since December 2010, political instability has increased markedly in a number of countries in the Middle East and North Africa. As a result of the civil war in Syria, hundreds of thousands of Syrian refugees have fled to Turkey and more can be expected to cross the border as the conflict continues. Moreover, tensions continue between Turkey and Syria, and Turkey's relations with Russia have recently deteriorated.

The current conflict with the terrorist group Islamic State in Iraq and Syria ("ISIS"), as well as tension in and involving the Kurdish regions of northern Iraq, which are contiguous to the region where our southeast Turkey licenses are located, may have political, social or security implications in Turkey or otherwise have a negative impact on the Turkish economy. Stability and security in Iraq deteriorated significantly since 2014 due to the conflict with ISIS.

Turkey has also experienced problems with domestic terrorist and ethnic separatist groups. For example, Turkey has been in conflict for many years with the People's Congress of Kurdistan (formerly known as the PKK), an organization that is listed as a terrorist organization by states and organizations, including Turkey, the European Union and the United States.

In response to escalating violence, the United States has increased military operations against ISIS. In addition, Turkey has authorized military action, engaging in recent land and air strikes, against ISIS and PKK. This instability has raised concerns regarding security in the region, including Turkey, and these situations may escalate in the future to more violent events.

The potential impact on our business from such events, conditions and conflicts in these countries is uncertain. We may be unable to access the locations where we conduct operations or transport oil to our offtakers in a reliable manner. 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 could experience labor disputes that could disrupt our business in the future.

As of December 31, 2015, approximately 39 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with PETROL-IS. In 2015, we negotiated a collective bargaining agreement with PETROL-IS covering approximately 41 employees at another of our subsidiaries operating in Turkey. Potential work disruptions from labor disputes with these employees could disrupt our business and adversely affect our financial condition and results of operations.

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

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

Risks Related to the Oil and Natural Gas Industry

Oil and natural gas prices are volatile. Continued or further declines in prices could adversely affect our financial condition, results of operations, cash flows, access to capital, and ability to grow.

Oil and natural gas prices historically have been volatile and may continue to be volatile in the future. Therefore, even if oil prices recover for a period of time, volatility will remain, and prices could move downward or upward on a rapid or repeated basis. The decline since late 2014 in oil and natural gas prices has reduced our revenue, cash flows and access to capital and, unless commodity prices improve, this trend will likely continue or worsen. Lower oil and natural gas prices also potentially reduce the amount of oil and natural gas that we can economically produce resulting in a reduction in the proved oil and natural gas reserves we could recognize. Thus, significant and sustained commodity price reductions could materially and adversely affect our financial condition and results of operations which could impact our ability to maintain or increase our current levels of borrowing, our ability to repay current or future indebtedness, our ability to refinance our current indebtedness or obtain additional capital on attractive terms.

The markets for crude oil and natural gas have historically been, and are likely to continue to be, volatile and subject to wide fluctuations in response to numerous factors, including the following:

- worldwide and domestic supplies of oil and gas, and the productive capacity of the oil and gas industry as a whole;
- changes in the supply and the level of consumer demand for such fuels;
- overall global and domestic economic conditions;
- political conditions in oil, natural gas, and other fuel-producing and fuel-consuming areas;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for crude oil or natural gas;
- the price and level of imports of crude oil, refined petroleum products, and liquefied natural gas;
- weather conditions, including effects of weather conditions on prices and supplies in worldwide energy markets;
- technological advances affecting energy consumption and conservation;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting countries to agree to and maintain crude oil prices and production controls;
- the competitive position of each such fuel as a source of energy as compared to other energy sources;
- strengthening and weakening of the U.S. Dollar relative to other currencies; and
- the effect of governmental regulations and taxes on the production, transportation, and sale of oil, natural gas, and other fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty, but in general we expect oil and gas prices to continue to fluctuate significantly.

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

Any material inaccuracies in our reserves estimates or underlying assumptions could materially affect the quantities and present values of our reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves that we may report. In order to prepare these estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves that we may report. In addition, we may adjust estimates of proved, probable and possible reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Moreover, there can be no assurance that our reserves will ultimately be produced or that our proved undeveloped, probable and possible reserves will be developed within the periods anticipated. Any significant variance in the assumptions could materially affect the estimated quantity and value of our reserves.

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

Future price declines may result in further write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas operations. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and natural gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each depletion pool to the estimated fair value (discounted future net cash flows of that depletion pool). Any such charge will not affect our cash flow from operating activities, but will reduce our earnings and shareholders' equity. For example, in the year ended December 31, 2015, as a result of significant declines in oil commodity prices, we incurred a loss of $16.0 million on proved impairment and exploratory well costs, not including an impairment on goodwill of $5.5 million. A further decline in oil or natural gas prices from current levels, or other factors, could cause a further impairment write-down of capitalized costs and a non-cash charge against future earnings. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date, even if oil or natural gas prices increase.

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 access to capital and our ability to economically find, develop or acquire reserves in commercial quantities.

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

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

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

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

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

After oil and natural gas prices recover, our long-term 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;
- declines in oil and natural gas prices; and
- shortages or delays in the availability of drilling rigs, equipment and qualified personnel.

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

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, 2015, approximately 47.5% of our total estimated net proved reserves in Turkey were proved undeveloped reserves. Undeveloped reserves, by their nature, are significantly less certain than developed reserves. At December 31, 2015, we also had a significant amount of unproved reserves, which consist of probable and possible reserves. There is significant uncertainty attached to unproved reserves estimates. The discovery, determination and exploitation of undeveloped or unproved reserves requires significant capital expenditures and successful drilling and exploration programs. We do not currently have the funds available to develop our undeveloped reserves. 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 production. Recently, there has been increased public concern regarding the potential environmental impact of fracture stimulation activities. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on drinking water supplies, the use of water in connection with completion operations, and the potential for impact to surface water, groundwater and the environment generally.

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

We are subject to operating hazards.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

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 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 seeking oil and natural gas exploration licenses and production licenses, and acquiring desirable producing properties or new leases for future exploration.

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.

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 29, 2016, Mr. Mitchell beneficially owned approximately 36% of our outstanding common shares. In addition, persons and entities affiliated with Mr. Mitchell participated in our offering of $55.0 million aggregate principal amount of Convertible Notes and have the right to convert their Convertible Notes to common shares subject to the terms and conditions of the Convertible Notes. Dalea Partners, LP, an affiliate of Mr. Mitchell, purchased $2.0 million of the Convertible Notes; trusts benefitting Mr. Mitchell's four children each purchased $2.0 million of the Convertible Notes; Pinon Foundation, a non-profit charitable organization directed by Mr. Mitchell's spouse, purchased $10.0 million of the Convertible Notes; and a trust benefitting Barbara and Terry Pope, Mr. Mitchell's sister-in-law and brother-in-law, purchased $200,000 of the Convertible Notes. Also, on December 30, 2015, we entered into a $5.0 million draw down convertible promissory note (the "Note") with ANBE Holdings L.P. ("ANBE"), an entity owned by the children of Mr. Mitchell, and controlled by an entity managed by Mr. Mitchell and his wife. ANBE has the right to convert the principal amount outstanding under the Note to common shares ($3.6 million as of December 31, 2015) subject to the terms and conditions of the Note. 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 your interests or the interests of our other shareholders.

We may seek to raise additional funds or restructure our debt by issuing securiti es that would dilute your ownership. Depending on the terms available to us, if these activities result in significant dilution, it may negatively impact the trading price of our common shares.

We may seek to raise additional funds or restructure our debt by issuing common shares, preferred shares, or securities convertible into or exercisable for common shares, that would dilute your ownership. Depending on the terms available to us, if these activities result in significant dilution, it may negatively impact the trading price of our common shares. Further, any additional financing that we secure may require the granting of rights, preferences or privileges senior to, or pari passu with, those of our common shares. Any issuances by us of equity securities may be at or below the prevailing market price of our common shares and in any event may have a dilutive impact on your ownership interest, which could cause the market price of our common shares to decline. We may also raise additional funds through the incurrence of convertible debt or the issuance or sale of other securities or instruments senior to our common shares. If we experience dilution from the issuance of additional securities and we grant superior rights to new securities over common shareholders, it may negatively impact the trading price of our common shares and you may lose all or part of your investment.

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

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

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

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 shareholder's investment in us.

Risks Related to Our Indebtedness

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our debt service and other obligations.

We have a significant amount of indebtedness. Our substantial indebtedness could have significant effects on our business. For example, it could:

- make it more difficult for us to satisfy our financial obligations, including with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing our indebtedness;
- increase our vulnerability to general adverse economic, industry and competitive conditions, especially declines in oil and natural gas prices;
- limit our ability to borrow additional funds, and
- limit our financial flexibility

Each of these factors may have a material and adverse effect on our financial condition and viability. Our ability to make payments with respect to our indebtedness and to satisfy any other debt obligations will depend on commodity prices, our ability to raise capital and our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting our company and industry, many of which are beyond our control.

Item 1B. Unresolved Staff Comments

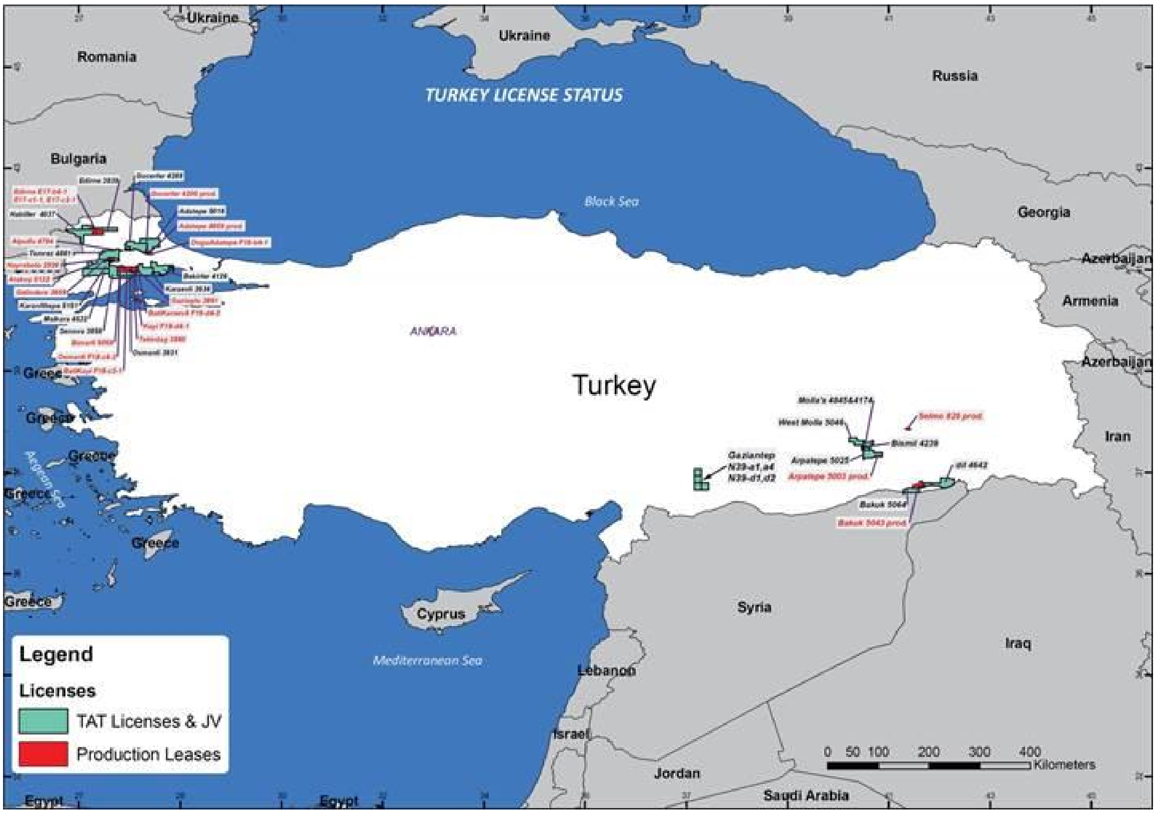
Not applicable.

Item 2. Properties

Turkey

General. As of December 31, 2015, we held interests in 18 onshore and offshore exploration licenses and 25 onshore production leases covering a total of approximately 1.4 million gross acres (approximately 880,000 net acres) in Turkey. We acquired our interests in Turkey through acquisitions, as well as through farm-in agreements with existing third-party license holders and through applications submitted to the Turkish General Directorate for Petroleum Affairs (the “GDPA”), the agency responsible for the regulation of oil and natural gas activities under the Ministry of Energy and Natural Resources in Turkey.

The following map shows our interests in Turkey:



Reserves. As of December 31, 2015, we had total net proved reserves of 10,815 Mbbl of oil and 15,847 Mmcf of natural gas, net probable reserves of 10,931 Mbbl of oil and 20,253 Mmcf of natural gas and net possible reserves of 11,205 Mbbl of oil and 70,739 Mmcf of natural gas in Turkey.

Equipment Yards. As of December 31, 2015, we leased equipment yards in Muratli, Diyarbakir and Tekirdag and owned equipment yards at Selmo and Edirne.

Commercial Terms. Turkey's fiscal regime for oil and natural gas licenses is presently comprised of royalties and income tax. The royalty rate is 12.5% and the corporate income tax rate is 20%. Our revenue from the Selmo oil field is subject to an additional 10% royalty, which is offset by the amount of exploration expense that TEMI and DMLP, the owners of our interest in the Selmo oil field, incur in Turkey. As of December 31, 2015, our carryforward exploration credit from TEMI and DMLP was $56.5 million and $6.2 million, respectively. If those exploration expenses do not equal or exceed the amount of this additional 10% royalty, we would owe the difference. Dividends repatriated from Turkey would be subject to a withholding tax rate of 15% unless reduced by a tax treaty. There is also an 18% value added tax. However, for exploration licenses, no value added tax is assessed on drilling, completion, workover, seismic and geologic activities.

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

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

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

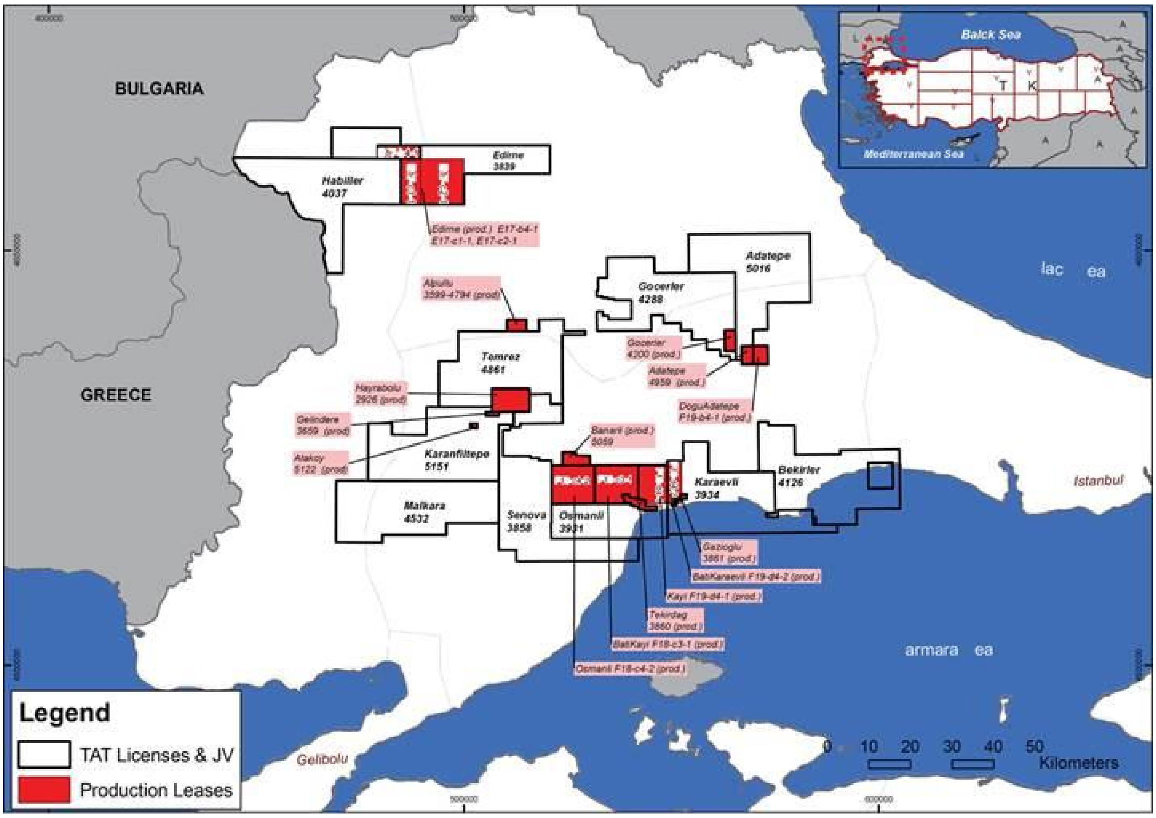
Once a discovery is made, the license holder may apply to convert the area, not to exceed 25,000 hectares (approximately 62,000 acres), to a lease. Under a lease, the lessee may produce oil and natural gas. The term of a lease is for 20 years and may be extended for two further terms of 10 years each.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

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

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

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

Northwestern Turkey. The following map shows our interests in northwestern Turkey at December 31, 2015:



Adatepe (Production Lease 4959 and License 5016). We own a 50% working interest in Production Lease 4959 and License 5016, which cover approximately 3,086 gross acres and 117,000 gross acres, respectively. As of December 31, 2015, we had six gross (three net) producing wells on the Adatepe Production Lease. We are the operator of Production Lease 4959 and License 5016. The current terms of Production Lease 4959 and License 5016 expire in September 2031 and January 2016, respectively. We are evaluating extension options for License 5016, and Production Lease 4959 has extensions available under the petroleum law.

Alpullu (Production Lease 4794) and Temrez (Licenses F17B3, F18A3, F18A4, and F18B4). We own a 100% working interest in the Alpullu Production Lease and the Temrez Licenses, which cover approximately 3,158 acres and 134,296 acres, respectively. As of December 31, 2015, we had nine gross (8.8 net) producing wells on the Alpullu Production Lease. We plan to maintain production to satisfy our obligation on the Alpullu Production Lease. We are the operator of the Alpullu Production Lease and the Temrez License, which expire in September 2028 and July 2020, respectively, with extensions available under the petroleum law.

Atakoy (Production Lease 5122). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 5122, which covers approximately 440 gross acres. As of December 31, 2015, we had 14 gross (5.8 net) producing wells on the Atakoy production lease. We plan to maintain production to satisfy our obligation on Production Lease 5122. We are the operator of Production Lease 5122, which expires in November 2032, with extensions available under the old and new petroleum laws.

Banarli (Production Lease 5059). We own a 50% working interest in Production Lease 5059, which covers approximately 4,608 gross acres. As of December 31, 2015, we had one gross (0.5 net) producing well on the Banarli Production Lease. We plan to maintain production to satisfy our obligation on Production Lease 5059. We are the operator of Production Lease 5059, which expires in February 2032, with extensions available under the petroleum law.

Bekirler (License 4126). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 4126, which covers approximately 124,000 gross acres. We are the operator of License 4126, which expired in December 2015, but we have filed an application to convert the productive areas into a new production lease.

Dogu Adatepe (Production Lease F19-b4-1). We own a 50% working interest in the Dogu Adatepe Production Lease, which covers part of our former Cayirdere license. The lease covers approximately 4,000 gross acres and expires in October 2017, with an additional 28 years of extensions under the new petroleum law available with the maintenance of production on the production lease.

Edirne Production Leases and Habiller Production Lease . We own a 55% working interest in three Edirne Production Leases and a 100% working interest in the Habiller Production Lease, which cover an aggregate of approximately 65,000 gross acres. As of December 31, 2015, we had 20 gross (14.7 net) producing wells on the Edirne and Habiller Production Leases. We are the operator of the Edirne Production Leases and the Habiller Production Lease which expire in 2034 and March 2020, respectively, with extensions available under the petroleum law.

Gocerler (Production Lease 4200 and License 4288). We own a 50% working interest in Production Lease 4200 and License 4288, which cover approximately 3,363 gross acres and 119,000 gross acres, respectively. As of December 31, 2015, we had seven gross (3.5 net) producing wells on the Gocerler Production Lease and 13 gross (6.4 net) producing wells on License 4288. We plan to drill one well in 2016 on License 4288 to satisfy the work program for License 4288 and we plan to maintain production to satisfy our obligations on Production Lease 4200. We are the operator of Production Lease 4200 and License 4288, which expire in May 2023 and August 2017, respectively, with extensions available under the petroleum law.

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 December 31, 2015, we had 16 gross (6.6 net) producing wells on the Hayrabolu Production Lease. We plan to maintain production which satisfies our obligation on Production Lease 2926. We are the operator of Production Lease 2926, which expires in February 2020, with one ten-year extension available under the old and new petroleum laws.

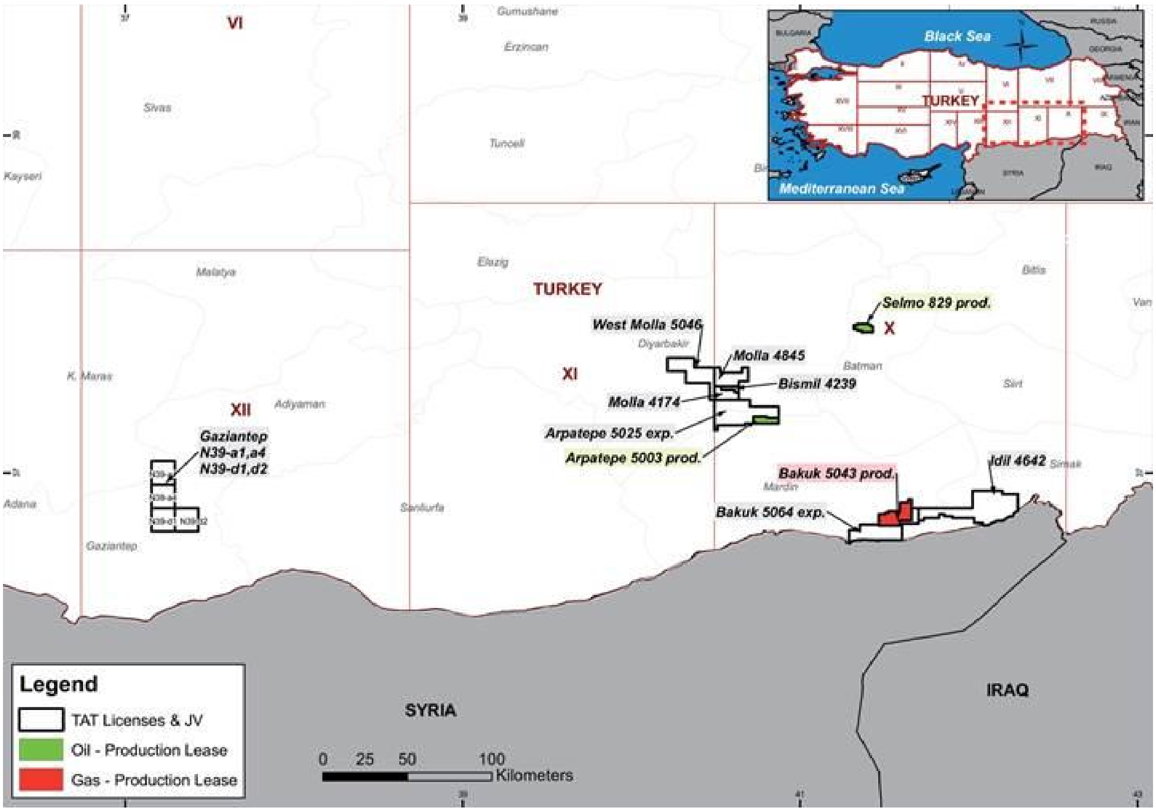
Karaevli (Production Lease). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in the Karaevli Production Lease, which covers approximately 8,500 gross acres. As of December 31, 2015, we had seven gross (2.9 net) producing wells on the Karaevli lease. We are the operator of the Karaevli Production Lease. The Karaevli Production Lease expires in November 2020, with extensions available under the petroleum law. We have submitted an application for another Karaevli Production Lease covering approximately 15,800 gross acres, which is pending.

Karanfiltepe (Licenses F17c-2,3 and F18d-1,2,4) . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in the Karanfiltepe licenses, which cover approximately 160,000 gross acres. As of December 31, 2015, we had five gross (2.1 net) producing wells on the Karanfiltepe licenses. We are the operator of the Karanfiltepe licenses, which expire in June 2020, with extensions available under the petroleum law.

Osmanli Production Leases. We own 41.5%, subject to a 0.415% overriding royalty interest, in six Osmanli Production Leases, which cover approximately 107,000 gross acres. As of December 31, 2015, we had 114 gross (47.3 net) producing wells on the Osmanli Production Leases. We are the operator of the Osmanli Production Leases, which will not expire for 40 years if production is maintained.

Tekirdag (Production Lease 3860) and Gazioglu (Production Lease 3861) . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Leases 3860 and 3861, which cover an aggregate of approximately 4,300 gross acres. As of December 31, 2015, we had 67 gross (28.2 net) producing wells on the Tekirdag and Gazioglu Production Leases. We plan to maintain production to satisfy our obligation on Production Leases 3860 and 3861. We are the operator of Production Leases 3860 and 3861, which expire in December 2023 and December 2021, respectively, with extensions available under the petroleum law.

Southeastern Turkey. The following map shows our interests in southeastern Turkey at December 31, 2015:



Arpatepe (Production Lease 5003 and License 5025). We own a 50% working interest in Production Lease 5003 and License 5025, which cover approximately 11,200 and 84,800 gross acres, respectively. For 2015, our wellhead production of oil from the Arpatepe field was 51,527 Bbls of oil, at an average rate of approximately 141 Bbl/d. As of December 31, 2015, we had seven gross (3.5 net) producing wells on the Arpatepe production lease. We are the operator of Production Lease 5003 and License 5025, which expire in November 2028 and February 2016, respectively, with extensions available under the old and new petroleum laws. We are working on establishing production and extending License 5025 for at least two years.

Bakuk (License 5064 and Production Lease 5043). We own a 50% working interest in License 5064 and Production Lease 5043. The exploration license covers approximately 61,000 gross acres, and the production lease covers approximately 34,400 gross acres. Production continues from the Bakuk-101 well, and we are evaluating additional offset well locations. Tiway Turkey, Ltd. (“Tiway”) is the operator of License 5064 and Production Lease 5043, which expire in June 2016 and January 2032, respectively, with extensions available under the petroleum law.

Bati Yasince Production Lease (Lease M45A1-1). We own a 100% working interest in the Bati Yasince Production Lease, which covers approximately 7,200 gross acres. We drilled the Bati Yasince-1 discovery well in the fourth quarter of 2014, which was producing oil as of December 31, 2015. We are the operator of the lease, which expires in 2035 with two 10 year extensions available under the petroleum law.

Gaziantep (Gaziantep Licenses). We own a 62.5% working interest in the Gaziantep Licenses, subject to a 0.313% overriding royalty interest, which cover an aggregate of 152,000 gross acres. We are the operator of the Gaziantep Licenses, which expire in October 2019. We are currently evaluating additional prospects on the Gaziantep Licenses, including an offset to the Alibey-1H discovery well.

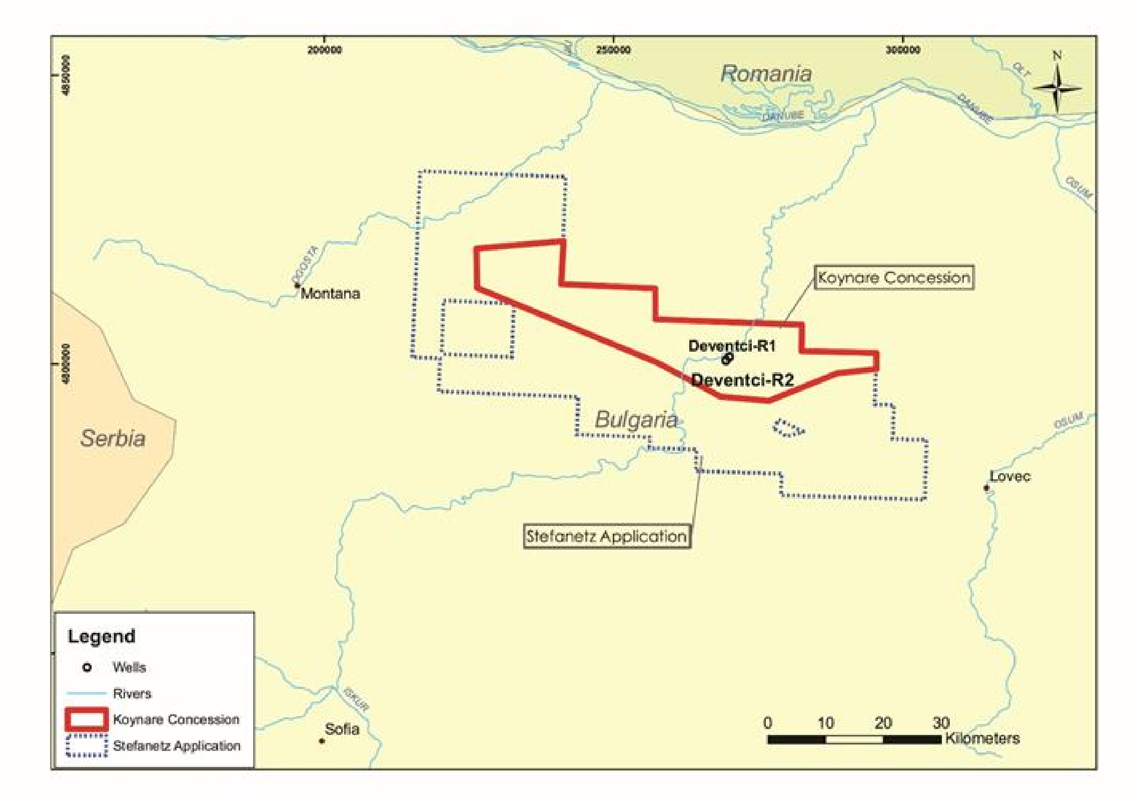
Idil (License 4642). We own a 50% working interest in License 4642, which covers approximately 123,000 gross acres. In February 2014, we entered into a farm-out agreement with Onshore Petroleum Company AS ("Onshore"). We are the operator of License 4642, which expires in October 2016.

Molla (Licenses 4174 and 4845) and West Molla (License 5046) . We own a 100% working interest in Licenses 4174, 4845 and 5046, which cover an aggregate of approximately 109,000 gross acres. As of December 31, 2015, we had six gross and net wells producing on the Molla licenses. We continue to interpret the 800 sq. km. 3D seismic data to delineate prospects on the Molla licenses. We are the operator of Licenses 4174, 4845 and 5046, which expire in June 2016, March 2017 and June 2016, respectively, with extensions available under the old and new petroleum laws.

Selmo (Production Lease 829). We own a 100% working interest in Production Lease 829, which covers 8,900 acres and includes the Selmo oil field. As of December 31, 2015, there were 69 gross and net producing wells on the Selmo production lease. For 2015, our wellhead production of oil in the Selmo field was approximately 934,777 Bbls of oil, at an average rate of approximately 2,561 Bbl/d. We are the operator of Production Lease 829, which expires in June 2025.

Bulgaria

General. As of December 31, 2015, we held interests in one onshore exploration permit and one onshore production concession in Bulgaria. We acquired all of our Bulgarian interests through the purchase of Direct Petroleum Bulgaria EOOD ("Direct Bulgaria") in February 2011. In January 2012, the Bulgarian Parliament enacted legislation that banned the fracture stimulation of oil and natural gas wells in the Republic of Bulgaria. The legislation also had the effect of preventing conventional drilling and completion activities. In June 2012, the Bulgarian Parliament amended the legislation to clarify that conventional drilling and completion activities were not intended to be affected by the law. As long as this legislation remains in effect, our unconventional natural gas exploration, development and production activities in Bulgaria will be significantly constrained. The following map shows our interests in Bulgaria at December 31, 2015:



Reserves. As of December 31, 2015, there were no economic reserves associated with our properties in Bulgaria.

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

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

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

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

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

Under an exploration permit, the government grants exploration rights for a term of up to five years to conduct seismic and other exploratory activities, including drilling. The recipient of an exploration permit commits to a work program and posts a bank guarantee in the amount of the estimated cost for the program. The area covered by an onshore exploration permit may be as large as 5,000 square kilometers. The exploration permit may be extended for up to two additional two-year terms, subject to fulfillment of minimum work programs, and may be extended for an additional one-year term in order to appraise potential geologic discoveries. Interests under an exploration permit are transferable, subject to government approval. The permit holder is required to pay an annual area fee equal to 40 Bulgarian Lev (approximately $25 at December 31, 2015) per square kilometer, or 40 Bulgarian Lev (approximately $25 at December 31, 2015) per square kilometer in the event the permit term is extended.

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

Koynare. We own a 100% working interest, subject to a 3.02% overriding royalty interest and Koynare Development Ltd.'s ("KDL") 50% farm-in interest, in the Koynare production concession covering approximately 163,000 acres. The Koynare Concession Area contains the Deventci-R1 well, where we discovered a reservoir in the Jurassic-aged Ozirovo formation at a depth of approximately 13,800 feet, which the Bulgarian government has certified as a geologic and commercial discovery. In November 2011, we commenced drilling the Deventci-R2 appraisal well on the Koynare Concession Area, which we suspended following the enactment of the Bulgarian government's January 2012 legislation. During the second half of 2013, we resumed drilling the Deventci-R2 directional well on our Koynare Concession Area. In January 2014, we reached target depth of 14,100 feet on the Deventci-R2 well, and conducted a long-term test on the well during the second quarter of 2014 with an initial production test of approximately 2.0 Mmcf/d of natural gas with condensates. In the fourth quarter of 2014, we received approval from the Bulgarian government to acidize the well. We conducted the acidizing operation in December 2014 to enhance its productivity. Following the acidizing operation, the Deventci-R2 well was deemed unproductive and was temporarily abandoned in the second quarter of 2015.

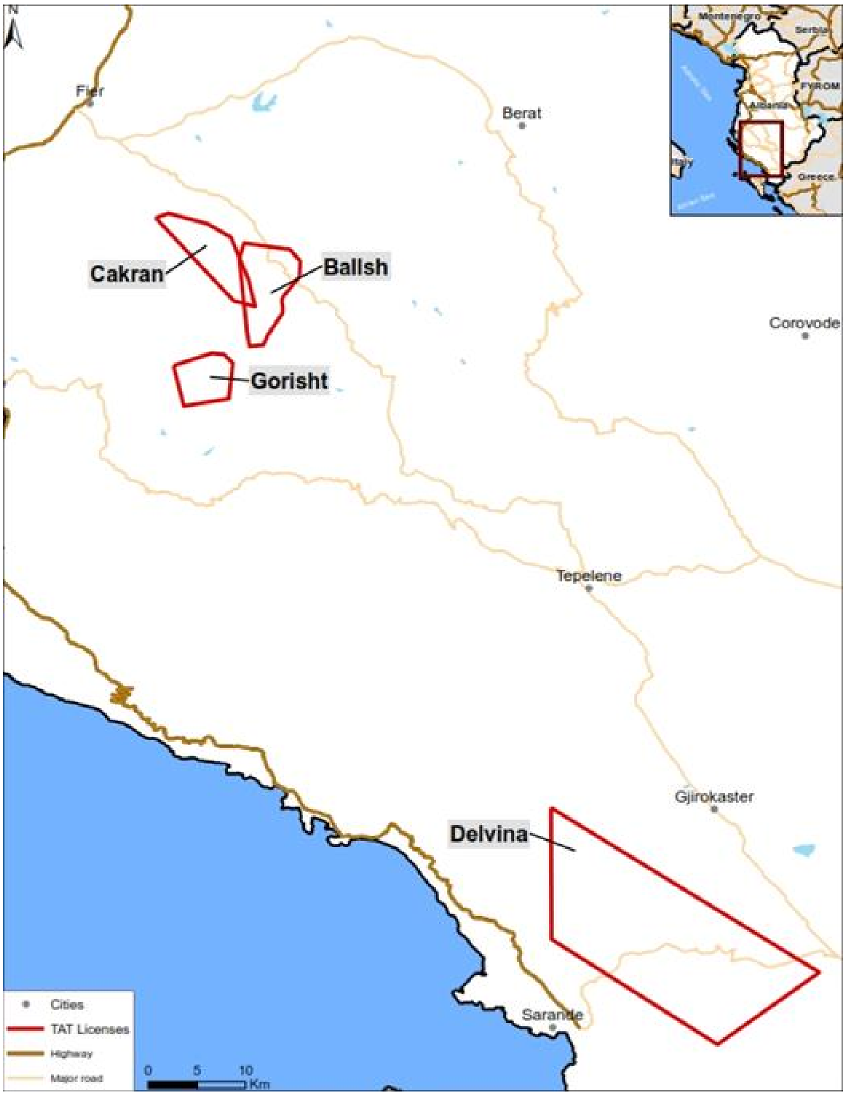
Stefenetz. In November 2011, we initiated the application process for a production concession covering approximately 395,000 acres over the southern portion of our former A-Lovech exploration permit. The Stefenetz Concession Area is estimated to contain over 300,000 prospective acres for Etropole shale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

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

Aglen. We have applied to relinquish 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.

Albania

General. As of December 31, 2015, we owned 100% of the interests in three onshore oil fields and one onshore gas field. The following map shows our interests in Albania at December 31, 2015:



Reserves. As of December 31, 2015, we had total net proved reserves of 4,258 Mbbl of oil and 5,527 Mmcf of natural gas, net probable reserves of 13,062 Mbbl of oil and 14,256 Mmcf of natural gas and net possible reserves of 9,620 Mbbl of oil and 23,884 Mmcf of natural gas in Albania. In February 2016, we sold all of the outstanding equity in Stream to GBC Oil. Stream's wholly owned subsidiary, TransAtlantic Albania, owns all of our former Albanian assets and operations. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and the Delvina Gas Liabilities to Delvina Gas to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas. See “Item 1. Business—Recent Developments.”

Commercial Terms. The following description of the commercial terms in Albania is limited to the Delvina gas field. The Delvina gas field is subject to a License Agreement between Agjencia Kombëtare e Burimeve Natyrore, the Albanian National Agency of Natural Resources (“AKBN”), and Albpetrol, the state owned oil company in Albania, and a Petroleum Agreement with Albpetrol, which together give the owner the right to access and develop the onshore gas field. The License Agreement has a 25-year term, with unlimited five-year renewal options.

The operator is required to submit annual work programs and budgets to Albpetrol each year, including the nature and amount of capital expenditures, which is required to be consistent with the plans of development (“PODs”) for the Delvina gas field approved by AKBN. Significant deviations from the PODs are subject to the approval of AKBN and Albpetrol.

Pursuant to the terms of the Petroleum Agreement, the operator pays a 2% to 7.2% gross over-riding royalty to Albpetrol, which may be paid in kind or cash. In addition, the operator is required to pay a royalty to Albpetrol based on the amount of pre-existing production (“PEP”) from the wells taken over from Albpetrol. The PEP royalty is calculated on a well by well basis and is initially equal to 65% to 70% of the PEP preceding the takeover of the well from Albpetrol. The PEP royalty declines at a rate of 5% per year.

In 2008, a new 10% mineral tax was enacted by the Albanian Ministry of Finance. The new mineral tax is equal to 10% of gross sales after deducting any PEP royalties paid. Under the Petroleum Agreement, any new financial burdens (including new mineral taxes) are to be neutralized by amendments to the Petroleum Agreement. The operator is working with officials from Albpetrol and AKBN to finalize amendments to the Petroleum Agreement to neutralize the 10% mineral tax.

Delvina Field. The Delvina natural gas field was discovered in 1987 and produces natural gas and natural gas liquids from reservoirs at a depth of 2,800 to 3,500 meters from fractured carbonates of Cretaceous-Paleocene age. The Delvina natural gas field is connected to potential markets by an existing pipeline, but needs additional downstream capacity. The field has two previously producing vertical wells, the Delvina D4 and D12 wells.

Summary of Oil and Natural Gas Reserves

The following table summarizes our net proved, probable and possible reserves at December 31, 2015.

	Reserves		
	Oil and Condensate (Mbbl)	Natural Gas (Mmcf)	Total (Mboe)
Reserves Category			
Turkey ***(continuing operations)***			
Proved reserves			
Proved developed	5,598	8,776	7,061
Proved undeveloped	5,217	7,071	6,396
Total proved	10,815	15,847	13,457
Probable reserves			
Probable developed	1,062	2,931	1,551
Probable undeveloped	9,869	17,322	12,756
Total probable	10,931	20,253	14,307
Possible reserves			
Possible developed	1,249	2,832	1,721
Possible undeveloped	9,956	67,907	21,274
Total possible	11,205	70,739	22,995
Albania ***(discontinued operations)*** (1)			
Proved reserves			
Proved developed	4,085	935	4,241
Proved undeveloped	173	4,592	938
Total proved	4,258	5,527	5,179
Probable reserves			
Probable developed	12,391	1,233	12,597
Probable undeveloped	671	13,023	2,842
Total probable	13,062	14,256	15,439
Possible reserves			
Possible developed	8,533	2,421	8,937
Possible undeveloped	1,087	21,463	4,664
Total possible	9,620	23,884	13,601
Total			
Proved reserves			
Proved developed	9,683	9,711	11,302
Proved undeveloped	5,390	11,663	7,334
Total proved	15,073	21,374	18,636
Probable reserves			
Probable developed	13,453	4,164	14,148
Probable undeveloped	10,540	30,345	15,598
Total probable	23,993	34,509	29,746
Possible reserves			
Possible developed	9,782	5,253	10,658
Possible undeveloped	11,043	89,370	25,938
Total possible	20,825	94,623	36,596

(1) In February 2016, we sold all of the outstanding equity in Stream to GBC Oil. Stream's wholly owned subsidiary, TransAtlantic Albania, owns all of our former Albanian assets and operations. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and the Delvina Gas Liabilities to Delvina Gas to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas. As of December 31, 2015, our Albanian assets and liabilities were classified as held for sale and presented within discontinued operations for all periods presented in our consolidated financial statements in this Annual Report on Form 10-K.

Value of Proved Reserves

The following table shows our estimated future net revenue, PV-10 and Standardized Measure as of December 31, 2015:

	Turkey	Albania	Total
		(in thousands)	
Future net revenue (1)	$ 340,243	$ 62,738	$ 402,981
Total PV-10 (1)(2)	$ 222,497	$ 26,887	$ 249,384
Total Standardized Measure (1)	$ 199,227	$ 26,887	$ 226,114

(1) Includes amounts related to our Albanian assets that were sold in February 2016 As of December 31, 2015, our Albanian assets and liabilities were classified as held for sale and presented within discontinued operations for all periods presented in our consolidated financial statements in this Annual Report on Form 10-K.

(2) 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:

	Turkey	Albania	Total
		(in thousands)	
Total PV-10 (1)	$ 222,497	$ 26,887	$ 249,384
Future income taxes	(28,900)	-	(28,900)
Discount of future income taxes at 10% per annum	5,630	-	5,630
Standardized Measure	$ 199,227	$ 26,887	$ 226,114

(1) Includes amounts related to our Albanian assets that were sold in February 2016. As of December 31, 2015, our Albanian assets and liabilities were classified as held for sale and presented within discontinued operations for all periods presented in our consolidated financial statements in this Annual Report on Form 10-K.

The following discussion of our proved reserves, proved undeveloped reserves, probable reserves and possible reserves as of December 31, 2015 has not been adjusted to reflect the sale of our Albanian assets in February 2016.

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, 2015, our estimated proved reserves were 18,636 Mboe, a decrease of 14,113 Mboe, or 43.1%, compared to 32,749 Mboe at December 31, 2014. This decrease was primarily attributable to the substantial decline in oil prices which caused developed and undeveloped reserves to become uneconomic at an earlier time, and technical revisions on Albanian reserves based on actual performance following the 2015 work program.

At December 31, 2015, we recorded a decrease in proved reserves due to technical revisions of 12,303 Mbbl and 638 Mmcf (12,409 Mboe total). The revision in oil of 12,303 Mbbls was mostly attributable to pricing and economics due to the substantial decline in oil prices. As Brent oil price drops, wells become uneconomic at an earlier time thus reducing future reserves. Approximately 75% of these reductions were attributable to the Albania properties. There were no material revisions due to performance in Turkey. The revision in natural gas of 638 Mmcf was primarily attributable to a reduction in Delvina natural gas reserves of 2,722 Mmcf due to market constraints and a reduced realized price, which was partially offset by an increase in proved natural gas reserves for our Turkey assets of 2,084 Mmcf due to improved performance. The decrease in proved reserves also consisted of sales volumes of 2,066 Mboe in 2015, consisting of 1,651 Mbbls of oil and 2,491 Mmcf of natural gas. The estimated undiscounted capital costs associated with our proved reserves in Turkey is $167.9 million.

At December 31, 2015, we recorded an increase in proved reserves of 362 Mboe through extensions and discoveries. These increases were due to the discovery of productive pay in the Hazro formation in the Bahar oil field.

Proved Undeveloped Reserves

At December 31, 2015, our estimated proved undeveloped reserves were 7,334 Mboe, a decrease of 3,066 Mboe, or 29.5%, compared to 10,400 Mboe at December 31, 2014. Of this decrease in proved undeveloped reserves, 2,566 Mboe was due to lower pricing and capital constraints forcing a slower development of these locations. All of our proved undeveloped reserves as of December 31, 2015 will be developed within five years of the date the reserve was first disclosed as a proved undeveloped reserve. The estimated undiscounted capital costs associated with our proved undeveloped reserves in Turkey is $163.1 million of which $1.5 million is expected to be incurred in 2016. In addition, during 2015, we converted 500 Mboe from proved undeveloped to proved developed reserves and incurred $8.6 million of capital expenditures during 2015 to convert such reserves.

The proved undeveloped reserves assume development costs will be funded from future cash flows from operations and financing activities, which may not be sufficient or available at commercially economic terms and could impact the timing of these development activities.

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.

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.

Internal Controls

Management has established, and is responsible for, a number of internal controls designed to provide reasonable assurance that the estimates of proved, probable and possible reserves are computed and reported in accordance with rules and regulations provided by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls consist of documented process workflows and qualified professional engineering and geological personnel with specific reservoir experience. We also retain an outside independent engineering firm to prepare estimates of our proved, probable and possible reserves. We work closely with this firm, and management is responsible for providing accurate operating and technical data to it. Management has tested the processes and controls regarding our reserves estimates for 2015. Senior management reviews and approves our reserves estimates, whether prepared internally or by third parties. In addition, our audit committee serves as our reserves committee and is composed of three outside directors, all of whom have experience in the review of energy company reserves evaluations. The audit committee reviews the final reserves estimate and also meets with representatives from the outside engineering firm to discuss their process and findings.

Oil and Natural Gas Reserves under U.S. Law

In the United States, we are required to disclose proved reserves, and we are permitted to disclose probable and possible reserves, using the standards contained in Rule 4-10(a) of the SEC's Regulation S-X. The estimates of proved, probable and possible reserves presented as of December 31, 2015 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 32 years of experience in oil and natural gas reservoir studies and evaluations and is a member of the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with DeGolyer and MacNaughton to ensure the integrity, accuracy and timeliness of data furnished to them for the preparation of their reserves estimates. Our vice president of engineering has over 13 years of experience in oil and natural gas reservoir studies and evaluations. He has a Bachelor of Science degree in Petroleum Engineering from Texas Tech University.

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

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

The estimates of proved, probable and possible reserves prepared by DeGolyer and MacNaughton for the year ended December 31, 2015 included a detailed evaluation of our Selmo, Arpatepe, Bakuk, Molla and Thrace Basin properties in Turkey, our Cakran, Gorisht, Ballsh and Delvina properties in Albania and our West Koynare field in Bulgaria. DeGolyer and MacNaughton determined that their estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about whether proved reserves are economically producible from a given date forward, under existing economic conditions, operating methods and government regulations, consistent with the definition in Rule 4-10(a)(24) of SEC Regulation S-X.

Oil and Natural Gas Reserves under Canadian Law

As a reporting issuer under Alberta, British Columbia and Ontario securities laws, we are required under Canadian law to comply with National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”) implemented by the members of the Canadian Securities Administrators in all of our reserves related disclosures. DeGolyer and MacNaughton evaluated the Company’s reserves as of December 31, 2015, 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.

Oil and Natural Gas Sales Volumes

The following table sets forth our sales volumes of oil and natural gas (including by field for any field that contained 15% or more of our total proved reserves at December 31, 2015) for 2015, 2014 and 2013:

	Sales Volumes		
Year	Oil (1) (Bbls)	Natural Gas (Mcf)	Total (Boe)
2015			
Total Turkey	1,420,035	2,491,017	1,835,205
Selmo field	933,925	–	933,925
Bahar field	431,199	–	431,199
Total Albania	230,855	–	230,855
2014			
Total Turkey	1,302,439	3,258,537	1,845,529
Selmo field	1,023,877	–	1,023,877
Total Albania	36,200	–	36,200
Gorisht-Kocul field	19,306	–	19,306
2013			
Total Turkey	932,463	3,495,698	1,515,079
Selmo field	665,025	–	665,025

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

Average Sales Price and Production Costs

The following table sets forth the average sales price per Bbl of oil and Mcf of natural gas and the average production cost, not including ad valorem and severance taxes, per unit of production for each of 2015, 2014 and 2013:

	2015	2014	2013
Turkey:			
Average Sales Price Oil ($/Bbl)	$ 44.69	$ 82.92	$ 101.05
Natural Gas ($/Mcf)	$ 7.73	$ 8.67	$ 9.43
Unit Costs Production ($/Boe)	$ 6.10	$ 8.56	$ 10.62
Albania:			
Average Sales Price Oil ($/Bbl)	$ 37.10	$ 52.43	$ –
Unit Costs Production ($/Boe)	$ 26.02	$ 31.15	$ –

Drilling Activity

The following table sets forth the number of net productive and dry exploratory wells and net productive and dry development wells we drilled in 2015, 2014 and 2013:

	Development Wells		Exploratory Wells	
	Productive	Dry	Productive	Dry
Turkey:				
2015	2.4	-	-	1.4
2014	14.7	2.0	4.6	0.4
2013	10.5	0.5	3.5	4.4
Bulgaria:				
2015	–	–	–	0.3
2014	–	–	–	–
2013	–	–	–	–
Albania:				
2015	–	–	–	–
2014	–	–	–	–
2013	–	–	–	–

Oil and Natural Gas Properties, Wells, Operations and Acreage

The following discussion of our productive wells, developed acreage and undeveloped acreage as of December 31, 2015 has not been adjusted to reflect the sale of our Albanian assets in February 2016.

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, 2015:

	Oil		Natural Gas	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Turkey	84.0	79.9	164.0	76.2
Bulgaria	–	–	–	–
Albania	215.0	215.0	1.0	1.0

(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, 2015:

	Developed Acres	
	Gross (1)	Net (2)
Turkey	278,000	148,000
Albania	20,000	20,000
Total	298,000	168,000

(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, 2015:

	Undeveloped Acres	
	Gross (1)	Net (2)
Turkey	1,105,000	732,000
Bulgaria	567,000	567,000
Albania	56,000	56,000
Total	1,728,000	1,355,000

(1) "Gross" means the total number of acres in which we had a working interest.
(2) "Net" means the sum of the fractional working interests owned in gross acres.

Undeveloped Acreage Expirations. The following table summarizes by year our undeveloped acreage as of December 31, 2015 that is scheduled to expire in the next five years:

	Undeveloped Acres (1)		% of Total Undeveloped Acres
	Gross (2)	Net (3)	Net (3)
2016	506,290	343,490	25.0
2017	152,006	92,361	7.0
2018	–	–	–
2019	152,107	95,067	7.0
2020	294,761	200,889	15.0

(1) Excludes the Stefenetz Concession Area for which we have applied for a production concession.
(2) "Gross" means the total number of acres in which we had a working interest.
(3) "Net" means the sum of the fractional working interests owned in gross acres.

We anticipate that we will be able to extend the license terms for substantially all of our undeveloped acreage in Turkey scheduled to expire in 2016 through the execution of our current work commitments.

Item 3. Legal Proceedings

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

In 2003, the villagers applied to the Kozluk Civil Court of First Instance in Turkey with seven title survey certificates dating back to Ottoman times. These villagers were granted title registration certificates, and in 2005, these villagers applied to the Kozluk Civil Court of First Instance to enlarge the areas covered by the certificates to approximately 20 square kilometers. Neither we nor, to our knowledge, any ministry in the Turkish government received notice of this court proceeding. Almost all of our production wells at the Selmo oil field lie within this enlarged area. In 2009, the Supreme Court overruled the Kozluk Civil Court of First Instance and directed it to re-examine the case (the "Surface Litigation").

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

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

On June 27, 2012, the Kozluk Civil Court of First Instance dismissed the Surface Litigation. The court issued its formal decision on August 8, 2012, and the plaintiffs filed an appeal with the Court of Appeal. The file was reversed by the Court of Appeal and sent back to the Kozluk Civil Court of First Instance in August 2014. The Court of Appeals ruled that the Kozluck Civil Court of First Instance investigate the merits of the dispute to determine the ownership position of the parties, that TPAO should be added as a party to the litigation, and that the cadastral map sheet depicting the real properties at issue must be investigated. The parties then appealed to the Court of Appeals for correction of judgment.

We continue to operate on the surface at Selmo, and have paid surface damages for locations at Selmo from the time we began operating the Selmo lease to present.

Direct Petroleum. In December 2014, Direct Petroleum LLC ("Direct") filed suit against the Company alleging that it was due liquidated damages of $5.0 million worth of common shares of the Company pursuant to the second amendment of the purchase agreement between the Company and Direct. On March 15, 2016, the Company entered into a settlement agreement pursuant to which we agreed to issue 225,000 common shares of the Company to Direct in exchange for a mutual release of all current and future claims against the other party in connection with the purchase agreement.

Bulgarian Ministry of Energy and Economy. In October 2015, the Bulgarian Ministry of Energy and Economy filed a suit against Direct Bulgaria, claiming a $200,000 penalty for Direct Bulgaria's alleged failure to fulfill the work program associated with the Aglen exploration permit. Direct Bulgaria received a force majeure recognition in 2012 from the Bulgarian Ministry of Energy and Economy, and the force majeure event has not been rectified. We believe that Direct Bulgaria is not under any obligation to fulfill the work program until the force majeure event is rectified, and continue to vigorously defend this claim.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Canada

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

	High	Low
2015		
Fourth Quarter	$ 4.30	$ 1.41
Third Quarter	$ 6.79	$ 3.22
Second Quarter	$ 7.50	$ 5.78
First Quarter	$ 6.80	$ 5.30
2014:		
Fourth Quarter	$ 9.85	$ 6.00
Third Quarter	$ 13.29	$ 10.10
Second Quarter	$ 12.04	$ 8.62
First Quarter	$ 9.80	$ 7.80

United States

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

	High	Low
2015:		
Fourth Quarter	$ 3.31	$ 1.02
Third Quarter	$ 5.40	$ 2.38
Second Quarter	$ 6.18	$ 4.81
First Quarter	$ 5.65	$ 4.04
2014:		
Fourth Quarter	$ 8.65	$ 5.15
Third Quarter	$ 12.48	$ 8.99
Second Quarter	$ 11.39	$ 7.89
First Quarter	$ 8.84	$ 7.00

Common Shares and Dividends

As of March 29, 2016, we had 41,106,194 common shares issued and outstanding and held by 88 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.

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.

Issuer Purchases of Equity Securities

The following table summarizes the Company's repurchase of common shares during the fourth quarter of 2015:

	Total Number of Shares Purchases	Average Price Paid per share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Programs	Maximum Number of Shares that May Yet be Purchased under Plan or Programs (1)
October 2015	10,199	$ 2.64	10,199	1,666,722
November 2015	-	$ -	-	1,666,722
December 2015	-	$ -	-	1,666,722
	10,199		10,199	

(1) In March 2015, the Company's board of directors approved a share repurchase plan which authorized the Company to repurchase up to 2.0 million common shares (the "Share Repurchase Program"). Under the Share Repurchase Program, the Company may purchase common shares from time to time through December 31, 2015 in the open market or through privately negotiated transactions. Purchases under the Share Repurchase Program must be in accordance with the guidelines specified in Rule 10b5-1 and Rule 10b-18 (to the extent applicable) under the Exchange Act.

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, 2015. All periods presented have been adjusted to reflect our oilfield services business segment, Moroccan segment, and the Albanian 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,				
	2015	2014	2013	2012	2011
	(amounts in thousands, except per share amounts)				
Total revenues	$ 85,064	$ 138,830	$ 130,827	$ 143,908	$ 128,905
Seismic and other exploration	370	4,285	14,009	5,040	11,542
Net (loss) income from continuing operations	(26,665)	29,214	(13,271)	(6,373)	(77,574)
Net (loss) income from discontinued operations	(80,873)	(138)	(442)	22,619	(43,369)
Comprehensive (loss) income	(149,818)	14,751	(50,686)	38,470	(173,012)
Basic net (loss) income per common share from continuing operations	(0.65)	0.77	(0.36)	(0.17)	(2.18)
Basic weighted average number of shares outstanding	40,841	37,829	37,069	36,742	35,597

	As of December 31,				
	2015	2014	2013	2012	2011
	(amounts in thousands)				
Total assets	$ 299,449	$ 546,236	$ 346,586	$ 358,258	$ 448,802
Long-term liabilities	103,537	185,782	63,619	72,819	112,904
Shareholders' equity	58,922	211,464	167,317	213,827	171,273
Capital expenditures, including acquisitions (1)	22,466	111,501	99,951	81,824	152,440

(1) Excludes seismic and other exploration expenditures.

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

We are an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established, yet underexplored, petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2015, we held interests in approximately 880,000 and 567,000 net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria, respectively. As of March 29, 2016, approximately 36% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, the chairman of our board of directors and our chief executive officer.

Decline in Oil Prices, Effect on Liquidity and Going Concern

Due to the significant decline in Brent crude oil prices during 2015, the borrowing base under the Company's senior credit facility (the "Senior Credit Facility") with BNP Paribas (Suisse) SA ("BNP Paribas") and the International Finance Corporation ("IFC") was decreased to $16.6 million effective December 30, 2015. The decline in the borrowing base resulted in a $15.5 million borrowing base deficiency under the Senior Credit Facility as of December 30, 2015.

On December 30, 2015, the lenders granted us a waiver of certain defaults under the Senior Credit Facility that existed as of December 30, 2015, including, among other things, the borrowing base deficiency. The waiver is conditioned upon, among other things, no borrowing base deficiency existing as of March 31, 2016.

As of December 31, 2015, the Company had $32.1 million outstanding under the Senior Credit Facility and no availability and was not in compliance with the current ratio financial covenant in the Senior Credit Facility. As of March 30, 2016, the borrowing base deficiency was $14.2 million.

We have negotiated a preliminary waiver of the existing defaults under the Senior Credit Facility and an extension of the borrowing base deficiency repayment obligation until at least September 30, 2016. This preliminary waiver and extension is subject to the approval of the lenders' respective credit committees. The lenders have advised us that they will seek credit committee approval of the preliminary waiver and extension in early April 2016. We cannot guarantee that this waiver and extension will be approved by our lenders. Because we are currently in default under the Senior Credit Facility and will be unable to repay the borrowing base deficiency by March 31, 2016, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, could foreclose against the assets securing their borrowings, and we could be forced into bankruptcy or liquidation. In addition, a payment default under the Senior Credit Facility could result in a cross default under our Convertible Notes.

Given the unfavorable market conditions and our limited access to capital, we are focused on the following near-term business strategies: (i) curing, waiving or extending the deadline to repay the borrowing base deficiency repayment obligation, (ii) the sale of assets to raise cash (iii) a significantly reduced development plan focused on maintaining our acreage position by drilling obligation wells and performing low cost, high return well optimizations, (iv) continued cost reduction measures to reduce our operating costs and general and administrative expenses and (v) restructuring or repaying our debt obligations, including the Senior Credit Facility and our Convertible Notes. During 2015, our cost reduction efforts included: (i) staff reductions, (ii) office relocations, (iii) negotiations with several key vendors to reduce exploration and development expenses and operating costs, and (iv) optimization of well designs. Notwithstanding these measures, there can be no assurance that we will be able to successfully sell assets or cure, waive or extend the deadline to repay the borrowing base deficiency repayment obligation.

These factors raise substantial doubt about our ability to continue as a going concern. The consolidated financial statements included in this report do not include any adjustments relating to the recoverability and classification of recorded asset amounts or amounts of liabilities that might result from the outcome of this uncertainty.

Recent Developments

Sale of Albania Oil Operations. In February 2016, we sold all of the outstanding equity in our wholly-owned subsidiary, Stream Oil & Gas Ltd. ("Stream"), to GBC Oil Company Ltd. ("GBC Oil") in exchange for (i) the future payment of $2.3 million to Raiffeisen Bank Sh.A ("Raiffeisen") to pay down a term loan facility (the "Term Loan Facility") dated as of September 17, 2014 between Stream's wholly-owned subsidiary, TransAtlantic Albania Ltd. ("TransAtlantic Albania"), and Raiffeisen, and (ii) the assumption of $29.2 million of liabilities owed by Stream, consisting of $23.1 million of accounts payable and accrued liabilities and $6.1 million of debt. TransAtlantic Albania owns all of our former Albanian assets and operations. In addition, GBC Oil issued us a warrant pursuant to which we have the option to acquire up to 25% of the fully diluted equity interests in TransAtlantic Albania for nominal consideration at any time on or before March 1, 2019. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and

$12.9 million of associated liabilities (the "Delvina Gas Lia bilities") to Delvina Gas Company, Ltd. ("Delvina Gas"), our newly formed, wholly-owned subsidiary, to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. In addition, we agreed to indemnify GBC Oil and Stream for the Delvina Gas Liabilities. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas.

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

2015 Financial and Operational Performance

- We derived 74.6% of our revenues from the production of oil, 22.6% of our revenues from the production of natural gas and 2.8% of our revenues from other sources during the year ended December 31, 2015.
- Total oil and natural gas sales revenues decreased 39.3% to $82.7 million for the year ended December 31, 2015, from $136.3 million in 2014. The decrease was primarily the result of a decrease in the average sales price of $28.75 per Boe, and a decrease in sales volumes of 11 Mboe.
- Wellhead production was 1,426 Mbbls of oil and 2,674 Mmcf of natural gas for the year ended December 31, 2015, as compared to 1,345 Mbbls of oil and 3,567 Mmcf of natural gas for 2014.
- In 2015, we incurred $22.8 million in total capital expenditures, including license acquisition, seismic and corporate expenditures, from continuing operations, as compared to $115.8 million in 2014.
- As of December 31, 2015, we had $55.0 million in long-term debt and $41.9 million in short-term debt (excluding liabilities held for sale of $6.1 million), as compared to $100.9 million in long-term debt and $34.8 million in short-term debt (excluding liabilities held for sale of $22.9 million) as of December 31, 2014.

Discontinued Operations in Albania

On November 16, 2015, we decided to launch a marketing process for our Albania assets and operations. As of December 31, 2015 we have classified our Albania segment assets and liabilities as held for sale and presented the operating results within discontinued operations for all periods presented. We recorded an impairment charge of $73.0 million to write down the net book value of the Albanian assets held for sale to their fair value as of December 31, 2015.

2015 Operations

During 2015, we pursued a reduced development plan that consisted of maintaining our acreage position by drilling obligation wells and performing low cost, high return well optimizations. We also launched an auction process for the sale of our Albanian assets and operations and repaid $36.2 million on our Senior Credit Facility. For additional information on our current operations, see "Item 1. Business—Current Operations."

Planned Operations

Assuming we have access to sufficient capital, we plan to satisfy license earning obligations for our core properties in Turkey and to pursue the sale of certain assets during 2016. For more information on our planned 2016 operations, see "Item 1. Business—Planned Operations."

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosures. Our significant accounting policies are described in "Note 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 fina ncial 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 generally must be made within one year from the completion of drilling activities. The acquisition costs of unproved acreage are initially capitalized and are carried at cost, net of accumulated impairment provisions, until such leases are transferred to proved properties or charged to exploration expense as impairments of unproved properties.

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

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

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

Foreign Currency Translation and Remeasurement. We follow ASC 830, *Foreign Currency Matters* ("ASC 830") which requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. The functional currency for each of our subsidiaries in Turkey and Bulgaria is the local currency and is the U.S. Dollar in Albania. For certain entities, translation adjustments result from the process of translating the functional currency of the foreign operation's financial statements into our U.S. Dollar reporting currency, which is a non-cash transaction. These translation adjustments are reported separately and accumulated in the consolidated balance sheets as a component of accumulated other comprehensive loss.

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

Goodwill. In accordance with ASC 350, Intangibles-Goodwill and Other ("ASC 350"), goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise. ASC 350 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. At December 31, 2015, we performed our annual assessment of goodwill and determined it was necessary to perform the two-step goodwill impairment test. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the reporting unit was less than its carrying amount based on our reserves report, dated December 31, 2015. The decline in our Turkey reserve report values was primarily due to the decline in the Brent oil price during the three months ended December 31, 2015.

Therefore, we performed step two of the impairment test, which indicated that the entire balance of goodwill was impaired. As a result, we recorded an impairment equal to the carrying amount of goodwill, or $5.5 million, at December 31, 2015 which is included in exploration, abandonment and impairment in the accompanying consolidated statement of comprehensive income (loss) for the year ended December 31, 2015.

Oil and Gas Reserves. The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the Securities and Exchange and the Financial Accounting Standards Board ("FASB"). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. We engaged DeGolyer and MacNaughton, our independent reserve engineers, to independently evaluate our properties that result in estimates for all of our estimated proved reserves at December 31, 2015.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

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

Other Recent Accounting Pronouncements and Reporting Rules

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU 2014-15"), an amendment to FASB Accounting Standards Codification ("ASC") Topic 205, *Presentation of Financial Statements*. This update provides guidance on management's responsibility in evaluating whether there is a substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. We have adopted ASU 2014-15 for the year ended December 31, 2015. See disclosure in Note 2, "Going concern" to our consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-03"). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. We currently recognize debt issuance costs as assets on our consolidated balance sheet. The recognition and measurement guidance for debt issuance costs are not affected by ASU 2015-03. ASU 2015-03 is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015 and early adoption is permitted. Currently, we do not expect the adoption of ASU 2015-03 to have a material impact on our consolidated financial statements or results of operations.

In July 2015, the FASB issued ASU 2015-11, *Simplifying the Measurement of Inventory* ("ASU 2015-11"), an amendment to ASC Subtopic 330-10. The amendment states that entities should measure inventory at the lower of cost and net realizable value. The amendment does not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. The amendment applies to all other inventory, which includes inventory that is measure using first-in, first-out (FIFO) or average cost. ASU 2015-11 is effective for fiscal years beginning after December 31, 2016, including interim periods within those fiscal years. We are currently assessing the potential impact of ASU 2015-11 on our consolidated financial statements and results of operations.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 805) Simplifying the Accounting for Measurement-Period Adjustments* ("ASU 2015-16"). ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. The amendments in the update should be applied prospectively to adjustments to provisional amounts that occur after the effective date of ASU 2015-16 with earlier application permitted for financial statements that have not been issued. As of December 31, 2015, we adopted ASU 2015-16 and have disclosed adjustments to our provisional amounts in Note 18, "Acquisitions" to our consolidated financial statements.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* ("ASU 2015-17"). ASU 2017-17 requires entities with a classified balance sheet to present all deferred tax assets and liabilities as noncurrent. ASU 2015-17 is effective for annual periods and interim periods in fiscal years beginning after December 15, 2016. As of December 31, 2015, we have adopted ASU 2015-17 and have adjusted the amounts in our consolidated balance sheet as of December 31, 2015 and 2014.

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

Results of Continuing Operations—Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

	Year Ended December 31, 2015	Year Ended December 31, 2014	Change 2015-2014
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	1,420	1,303	117
Natural gas (Mmcf)	2,491	3,262	(771)
Total production (Mboe)	1,835	1,846	(11)
Average daily sales volumes (Boepd)	5,028	5,058	(30)
Average prices:			
Oil (per Bbl)	$ 44.69	$ 82.93	$ (38.24)
Natural gas (per Mcf)	$ 7.73	$ 8.66	$ (0.93)
Oil equivalent (per Boe)	$ 45.07	$ 73.82	$ (28.75)
Revenues:			
Oil and natural gas sales	$ 82,716	$ 136,276	$ (53,560)
Sales of purchased natural gas	2,189	2,127	62
Other	159	427	(268)
Total revenues	85,064	138,830	(53,766)
Costs and expenses:			
Production	12,873	18,193	(5,320)
Exploration, abandonment and impairment	21,544	19,864	1,680
Cost of purchased natural gas	2,082	2,055	27
Seismic and other exploration	370	4,285	(3,915)
Revaluation of contingent consideration	-	(2,500)	2,500
General and administrative	24,138	31,071	(6,933)
Depletion	35,093	46,479	(11,386)
Depreciation and amortization	2,614	2,115	499
Interest and other expense	13,077	6,044	7,033
Foreign exchange loss	5,653	6,523	(870)
Deferred income tax expense	18,642	11,875	6,767
Gain (loss) on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	57,076	(2,100)	59,176
Change in fair value on commodity derivative contracts	(29,619)	39,554	(69,173)
Total gain on commodity derivative contracts	27,457	37,454	(9,997)
Oil and natural gas costs per Boe:			
Production	$ 6.14	$ 8.62	$ (2.48)
Depletion	$ 16.73	$ 22.03	$ (5.30)

Oil and Natural Gas Sales. Excluding sales of purchased natural gas, total oil and natural gas sales decreased to $82.7 million in 2015, from $136.3 million in 2014. Of this decrease, $52.8 million resulted from a lower average realized price per Boe in 2015. Our average price received decreased $28.75 to $45.07 per Boe in 2015, compared to $73.82 per Boe in 2014. Additionally, sales volumes decreased 11 Mboe which resulted in lower revenues of $0.8 million.

Production. Production expenses for the year ended December 31, 2015, dec reased to $12.9 million or $6.14 per Boe (WI), from $18.2 million or $8.62 per Boe (WI) for the year ended December 31, 2014. This decrease was primarily due to a higher devaluation of the New Turkish Lira ("TRY") compared to the U.S. Dollar in 2015, fewer workovers, reduced headcount and successful cost-cutting measures in our field operations for the year ended December 31, 2015.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs increased to $21.5 million in 2015, compared to $19.9 million for 2014. The increase was primarily due to $5.5 million of goodwill impairment, partially offset by a $3.9 million decrease in proved property impairment and impairment of exploratory well costs in 2015.

Seismic and Other Exploration. Seismic and other exploration costs decreased to $0.4 million for 2015, compared to $4.3 million for 2014. The decrease was primarily due to a decrease in seismic activities, which were conducted on our West Molla license during 2014.

Revaluation of Contingent Consideration. We completed the drilling and testing requirements pursuant to an amendment to the purchase agreement with Direct Petroleum LLC ("Direct"), which resulted in the reversal in 2014 of a $2.5 million contingent liability that was originally recorded in 2011.

General and Administrative. General and administrative expense decreased $6.9 million to $24.1 million for 2015, compared to $31.1 million for 2014. The decrease was primarily due to a decrease in legal, accounting and other services of $2.6 million, a decrease in office expense of $1.7 million, a decrease in bad debt expense of $1.2 million, a decrease in personnel expenses of $0.9, decrease in travel expense of $0.6 million and a decrease in vehicle expense of $0.2 million. In addition, severance expense was $1.3 million for 2015 compared to $0.3 million for 2014.

Depletion. Depletion expense decreased to $35.1 million or $16.73 per Boe for 2015, compared to $46.5 million or $22.03 per Boe for 2014. The decrease was due primarily to fewer additions to proved properties on our Selmo and Bahar fields, a 25.4% devaluation of the TRY compared to the U.S. Dollar in 2015 compared to an 8.6% devaluation during 2014 and a decrease in production volumes during 2015.

Interest and Other Expense. Interest and other expense increased to $13.1 million in 2015, compared to $6.0 million in 2014. The increase was primarily due to interest expense on $55.0 million aggregate principal amount of Convertible Notes, which were issued in December 2014 and January 2015.

Foreign Exchange Loss. We recorded a foreign exchange loss of $5.7 million in 2015, compared to $6.5 million in 2014. The change in foreign exchange is primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the TRY amount if it has not been settled previously. The decrease in foreign exchange loss in 2015 was due to a 25.4% devaluation of the TRY compared to the U.S. Dollar in 2015, compared to an 8.6% devaluation during 2014 and is offset by fluctuations in our U.S. Dollar denominated balances in Turkey.

Deferred Income Tax Expense. Deferred income tax expense increased to $18.6 million for the year ended December 31, 2015, compared to $11.9 million for 2014. The increase was primarily due to changes in our deferred tax liabilities related to our permanent reinvestment assertion in Turkey and increases in uncertain tax positions, which were partially offset by changes in temporary differences between our U.S. GAAP and statutory balances in Turkey.

Gain (Loss) on Commodity Derivative Contracts. During 2015, we recorded a net gain on commodity derivative contracts of $27.5 million, compared to a net gain of $37.5 million for 2014. In 2015, we recorded a $57.1 million gain on settled contracts and a $29.6 million loss to mark our commodity derivative contracts to their fair value. In 2014, we recorded a $39.6 million gain to mark our commodity derivative contracts to their fair value and a $2.1 million loss on settled contracts. We are required under our Senior Credit Facility to hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey.

Discontinued Operations. All revenues and expenses associated with our Albanian and Moroccan operations have been classified as discontinued operations. Our operating results from discontinued operations in Albania and Morocco are summarized as follows:

	Albania	Morocco	Total
		(in thousands)	
For the year ended December 31, 2015			
Total revenues	$ 8,565	$ –	$ 8,565
Production	11,615	–	11,615
Exploration, abandonment and impairment	86,577	–	86,577
Total costs and expenses	9,229	5	9,234
Total other income	1,819	–	1,819
Loss before income taxes	$ (97,037)	$ (5)	$ (97,042)
Income tax benefit	16,169	–	16,169
Loss from discontinued operations	$ (80,868)	$ (5)	$ (80,873)
For the year ended December 31, 2014 (1)			
Total revenues	$ 1,898	$ –	$ 1,898
Total costs and expenses	2,984	20	3,004
Total other income	356	–	356
Loss before income taxes	$ (730)	$ (20)	$ (750)
Income tax benefit	612	–	612
Loss from discontinued operations	$ (118)	$ (20)	$ (138)

(1) Our Albanian segment was acquired on November 18, 2014. Actual results include revenues and expenses from November 18, 2014 to December 31, 2014.

Results of Continuing Operations—Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

	Year Ended December 31, 2014	Year Ended December 31, 2013	Change 2014-2013
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	1,303	933	370
Natural gas (Mmcf)	3,262	3,512	(250)
Total production (Mboe)	1,846	1,518	328
Average daily sales volumes (Boepd)	5,058	4,159	899
Average prices:			
Oil (per Bbl)	$ 82.93	$ 101.02	$ (18.09)
Natural gas (per Mcf)	$ 8.66	$ 9.40	$ (0.74)
Oil equivalent (per Boe)	$ 73.82	$ 83.84	$ (10.02)
Revenues:			
Oil and natural gas sales	$ 136,276	$ 127,270	$ 9,006
Sales of purchased natural gas	2,127	2,581	(454)
Other	427	976	(549)
Total revenues	138,830	130,827	8,003
Costs and expenses:			
Production	18,193	18,602	(409)
Exploration, abandonment and impairment	19,864	27,333	(7,469)
Cost of purchased natural gas	2,055	2,247	(192)
Seismic and other exploration	4,285	14,009	(9,724)
Revaluation of contingent consideration	(2,500)	(5,000)	2,500
General and administrative	31,071	29,020	2,051
Depletion	46,479	38,996	7,483
Depreciation and amortization	2,115	2,326	(211)
Interest and other expense	6,044	3,929	2,115
Foreign exchange loss	6,523	9,663	(3,140)
Deferred income tax expense	11,875	979	10,896
Gain (loss) on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(2,100)	(3,521)	1,421
Change in fair value on commodity derivative contracts	39,554	823	38,731
Total gain (loss) on commodity derivative contracts	37,454	(2,698)	40,152
Oil and natural gas costs per Boe:			
Production	$ 8.62	$ 10.72	$ (2.10)
Depletion	$ 22.03	$ 22.48	$ (0.45)

Oil and Natural Gas Sales. Excluding sales of purchased natural gas, total oil and natural gas sales increased to $136.3 million in 2014, from $127.3 million in 2013. Of this increase, $27.5 million resulted from an increase in sales volumes of 328 Mboe. Sales volumes increased primarily on our southeast Turkey oil wells due to our successful horizontal drilling program in 2014. This increase was partially offset by a decrease of $18.5 million, attributable to a lower average realized prices per Boe in 2014. Our average price received decreased $10.02 to $73.82 per Boe in 2014, compared to $83.84 per Boe in 2013.

Production. Production expenses for 2014 decreased to $18.2 million, or $8.62 per Boe (WI) from $18.6 million, or $10.72 per Boe (WI) in 2013. The decrease of $2.10 per Boe was primarily attributable to an increase in our production volumes during 2014 compared to 2013.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs decreased to $19.9 million in 2014, compared to $27.3 million for 2013. The decrease was primarily due to a $15.5 million decrease in impairment of our exploratory well costs offset by a $6.5 million increase in other impairment and abandonment. The majority of our impairment and abandonment charges of $17.5 million in 2014 related to three exploratory wells in Turkey.

Seismic and Other Exploration. Seismic and other exploration costs decreased to $4.3 million for 2014, compared to $14.0 million for 2013. The decrease was primarily due to a decrease in seismic acquisition activities conducted on our West Molla license during 2013.

Revaluation of Contingent Consideration. We completed the drilling and testing requirements pursuant to an amendment to the purchase agreement with Direct, which resulted in the reversal in 2014 of a $2.5 million contingent liability that was originally recorded in 2011. During 2013, we recognized the reversal of a $5.0 million contingent liability that was originally recorded in 2011 as a result of entering into the amendment to the purchase agreement with Direct.

General and Administrative. General and administrative expense increased $2.1 million to $31.1 million for 2014, compared to $29.0 million for 2013. The increase was primarily due to a $1.5 million charge to bad debt expense for an uncollectible receivable and $1.1 million of acquisition expenses related to the acquisition of Stream. This was partially offset by a decrease in office rent expense of $0.3 million and personnel expenses of $0.3 million during 2014.

Depletion. Depletion expense increased to $46.5 million or $22.03 per Boe for 2014, compared to $39.0 million or $22.48 per Boe for 2013. The increase was due primarily to additions to proved properties on our Selmo and Bahar fields and an increase in production volumes during 2014.

Interest and Other Expense. Interest and other expense increased to $6.0 million in 2014, compared to $3.9 million in 2013. The increase was primarily due to an increase in our average level of debt outstanding during 2014 compared to 2013. Excluding debt assumed in the Stream acquisition, at December 31, 2014, we had $135.7 million of total debt outstanding, compared to $69.8 million at December 31, 2013. Also contributing to the increase was a $0.5 million write-off of loan financing costs related to our prior amended and restated credit facility, which was repaid in May 2014.

Foreign Exchange Loss. We recorded a foreign exchange loss of $6.5 million in 2014, compared to a loss of $9.7 million in 2013. The change in foreign exchange is primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the TRY amount if it has not been settled previously. The decrease in foreign exchange loss in 2014 was due to an 8.6% devaluation of the TRY compared to the U.S. Dollar in 2014, compared to a 19.7% devaluation during 2013.

Deferred Income Tax Expense. Deferred income tax expense increased to $11.9 million for the year ended December 31, 2014, compared to $1.0 million for 2013. The increase was primarily due to changes in temporary differences between our U.S. GAAP and statutory balances in Turkey.

Gain (Loss) on Commodity Derivative Contracts. During 2014, we recorded a net gain on commodity derivative contracts of $37.5 million, compared to a net loss of $2.7 million for 2013. In 2014, we recorded a $39.6 million gain to mark our commodity derivative contracts to their fair value and a $2.1 million loss on settled contracts. In 2013, we recorded a $0.8 million gain to mark our commodity derivative contracts to their fair value and a $3.5 million loss on settled contracts. We are required under our Senior Credit Facility to hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey.

Discontinued Operations. All revenues and expenses associated with our Albanian and Moroccan operations have been classifie d as discontinued operations. Our operating results from discontinued operations in Albania and Morocco are summarized as follows:

	Albania	Morocco	Total
		(in thousands)	
For the year ended December 31, 2014 (1)			
Total revenues	$ 1,898	$ –	$ 1,898
Total costs and expenses	2,984	20	3,004
Total other income	356	–	356
Loss before income taxes	$ (730)	$ (20)	$ (750)
Income tax benefit	612	–	612
Loss from discontinued operations	$ (118)	$ (20)	$ (138)
For the year ended December 31, 2013			
Total revenues	$ –	$ –	$ –
Total costs and expenses	–	505	505
Total other income	–	63	63
Loss before income taxes	$ –	$ (442)	$ (442)
Income tax benefit	–	–	–
Loss from discontinued operations	$ –	$ (442)	$ (442)

(1) Our Albanian segment was acquired on November 18, 2014. Actual results include revenues and expenses from November 18, 2014 to December 31, 2014.

Capital Expenditures

For 2015, we incurred $22.8 million in total capital expenditures, including license acquisition, seismic and corporate expenditures from continuing operations, compared to $115.8 million for 2014.

We expect our net field capital expenditures for 2016 to range between $5.0 million and $15.0 million. Given the market conditions and our limited access to capital, our 2016 development plan may be limited to drilling obligation wells and performing low cost, high return well optimizations. We expect net field capital expenditures during 2016 to include approximately $5.0 million of drilling and completion expense for gross obligation wells to hold one of our most promising licenses in Turkey. We expect cash on hand and cash flow from operations will be sufficient to fund our 2016 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2016 capital expenditure budget is subject to change.

Liquidity and Capital Resources

Our primary sources of liquidity for 2015 were our cash and cash equivalents, cash flow from operations, proceeds from the issuance of our Convertible Notes, borrowings under our convertible and promissory notes and unwinding of oil hedges. At December 31, 2015, we had cash and cash equivalents of $7.5 million, $55.0 million in long-term debt, $41.9 million in short-term debt and a working capital deficit of $30.1 million (excluding assets and liabilities held for sale), compared to cash and cash equivalents of $34.7 million, $100.9 million in long-term debt, $34.8 million in short-term debt and working capital of $11.2 million (excluding assets and liabilities held for sale) at December 31, 2014. Net cash provided by operating activities from continuing operations during 2015 was $86.5 million, an increase from net cash provided by operating activities from continuing operations of $77.9 million in 2014, due primarily to an increase in cash settlements on our commodity derivative contracts, which was partially offset by a decrease in our oil revenues.

Net cash used in investing activities from continuing operations during 2015 decreased to $31.7 million, compared to net cash used in investing activities from continuing operations of $115.5 million in 2014, due primarily to a decrease in drilling operations in light of the low oil price environment. Additionally, net cash used in financing activities from continuing operations was $40.3 million in 2015, compared to net cash provided by financing activities from continuing operations of $63.2 million in 2014, due primarily to higher loan repayments and a decrease in our borrowings in 2015.

As of December 31, 2015, the outstanding principal amount of our debt was $96.9 million (excluding liabilities held for sale). In addition to cash, cash equivalents and cash flow from operations, at December 31, 2015, we had a Senior Credit Facility, a credit facility with a Turkish bank, Convertible Notes, promissory notes, and a term loan facility (held for sale), all of which are discussed below.

Senior Credit Facility. On May 6, 2014, DMLP, TEMI, Talon Exploration, TransAtlantic Turkey Ltd., Amity and Petrogas (collecti vely the "Borrowers") entered into the Senior Credit Facility with BNP Paribas and the IFC. Each of the Borrowers is our wholly owned subsidiary. The Senior Credit Facility is guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide Ltd. (each, a "Guarantor").

The amount drawn under the Senior Credit Facility may not exceed the lesser of (i) $150.0 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. As of December 31, 2015, the lenders had an aggregate commitment of $40.0 million, with individual commitments of $20.0 million each. On the first day of each fiscal quarter commencing April 1, 2016, the lenders' commitments are subject to reduction in an amount equal to 7.69% of the aggregate commitments in effect on April 1, 2016.

The borrowing base amount is re-determined semi-annually on April 1st and October 1st of each year. The October 2015 redetermination decreased the borrowing base to $16.6 million effective December 30, 2015, which resulted in a $15.5 million borrowing base deficiency under the Senior Credit Facility as of December 30, 2015. 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; and
- the debt value which results in the loan life coverage ratio for such calculation date being 1.30 to 1.00.

The Senior Credit Facility matures on the earlier of (i) March 31, 2019, or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual banking case of BNP Paribas 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 banking case prepared by BNP Paribas and the Borrowers. The Senior 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 Senior Credit Facility accrue interest at a rate of three-month LIBOR plus 5.00% per annum (5.61% at December 31, 2015). The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.00% 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 Senior Credit Facility, and (b) 1.00% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Senior 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 BNP Paribas or (b) 5.00% for all other letters of credit.

The Senior 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 Senior Credit Facility, including maintaining the following financial ratios during the four most recently completed fiscal quarters occurring on or after March 31, 2014:

- 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 Senior 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 Senior 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) any other non-cash charges (including dry hole expenses and seismic expenses, to the extent such expenses would be capitalized under the "full cost" accounting method), (vii) 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), and (viii) transaction costs, expenses and fees incurred in connection with the negotiation, execution and delivery of the Senior Credit Facility and the related loan documents, 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 Senior Credit Facility, until amounts under the Senior 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, (xiv) open or maintain new deposit, securities or commodity accounts, (xv) use the proceeds from any loan in the territories of any country that is not a member of the World Bank, (xvi) incur any expenditure that is not covered by the projections in the most recent corporate cashflow projection, (xvii) modify its social and environmental action plans as determined in conjunction with IFC, (xviii) enter into any transaction or engage in any activity prohibited by the United Nations Security Council, or (xix) engage in any corrupt, fraudulent, coercive, collusive or obstructive practice.

An event of default under the Senior 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 Senior 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.

Pursuant to the Senior Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with BNP Paribas that hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey. As of December 31, 2015, TEMI had put contracts with BNP Paribas, which hedge the price of oil through March 2019.

At December 31, 2015, we had borrowings of $32.1 million under the Senior Credit Facility, a borrowing base deficiency of $15.5 million, and we were not in compliance with the current ratio financial covenant in the Senior Credit Facility. In December 2015, we were not in compliance with certain covenants under our Senior Credit Facility and the lenders declared an event of default and locked the Borrowers' collection accounts. On December 30, 2015, we entered into a Waiver and Consent Agreement with the lenders whereby the lenders provided a conditional waiver of the defaults including a waiver of cross-default under the Term Loan Facility, and permitted the Borrowers to make certain transfers and withdrawals under the collection accounts. Such waiver included certain conditions, including the following:

(i) The borrowing base deficiency must be repaid by March 31, 2016;

(ii) All monthly hedge settlement proceeds shall be used to pay down debt outstanding;

(iii) Net proceeds from certain asset sales shall be used to prepay loans outstanding under the Senior Credit Facility;

(iv) By June 30, 2016, the lenders shall be granted a security interest over all of the equity interests in Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") and all of the assets or property of TBNG; and

(v) On or before June 30, 2016, all holders of the Convertible Notes shall either (a) convert their debt interests under the Convertible Notes into equity interests, or (b) agree to extend the maturity of the Convertible Notes to April 1, 2019 or later on substantially identical terms.

In addition, we have negotiated a preliminary waiver of the existing defaults under the Senior Credit Facility and an extension of the borrowing base deficiency repayment obligation until at least September 30, 2016. This preliminary waiver and extension is subject to the approval of the lenders' respective credit committees. The lenders have advised us that they will seek credit committee approval of the preliminary waiver and extension in early April 2016. We cannot guarantee that this waiver and extension will be approved by our lenders. See "—Decline in Oil Prices, Effect on Liquidity and Going Concern."

At March 30, 2016, we had borrowings of $30.8 million under the Senior Credit Facility and a borrowing base deficiency of $14.2 million. We have classified all borrowings under the Senior Credit Facility as short-term debt as of December 31, 2015 due to the uncertainty regarding our ability to comply with the covenants in the Senior Credit Facility for the next twelve months.

TBNG Credit Facility. TBNG has a fully-drawn credit facility with a Turkish bank. During the fourth quarter of 2015, the facility was amended and now bears interest at a rate of 7.0% per annum and the monthly principal installments were deferred until March 29, 2016. The facility is due by June 29, 2016. The facility may be prepaid without penalty. The facility is secured by a lien on a Turkish real estate property owned by Gundem Turizm Yatirim ve Isletme A.S. ("Gundem"), which is 97.5% beneficially owned by Mr. Mitchell and his children. At December 31, 2015, TBNG had a balance of $5.2 million under the credit facility and no availability.

Convertible Notes. As of December 31, 2015, we had $55.0 million aggregate principal amount of outstanding Convertible Notes. The Convertible Notes were issued pursuant to an indenture, dated as of February 20, 2015 (the "Indenture"), between us and U.S. Bank National Association, as trustee (the "Trustee").

The Convertible Notes bear interest at an annual rate of 13.0%, payable semi-annually, in arrears, on January 1 and July 1 of each year. The Convertible Notes mature on July 1, 2017, unless earlier redeemed or converted.

Holders may from time to time at such holder's option, convert, subject to certain terms and conditions, any or all of the principal of any Convertible Note into fully paid and nonassessable common shares at the conversion price. The initial conversion price is $6.80 per common share, subject to adjustment as described in the Indenture. Prior to or contemporaneously with the conversion of any of the principal of a Convertible Note, all accrued but unpaid interest on the principal amount being converted will be paid in cash. The Convertible Notes may not be converted into common shares on the maturity date or the redemption date.

We may redeem all or part of the Convertible Notes at the redemption prices specified below (expressed in percentages of principal amount on the redemption date), plus accrued and unpaid interest to the redemption date.

Period Beginning	Redemption Price
January 1, 2016	105.0%
July 1, 2016	102.5%
January 1, 2017	100.0%

If we experience a fundamental change (as defined in the Indenture), we will be required to make an offer to repurchase the Convertible Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to but excluding the date of repurchase. Additionally, if we sell certain assets for $50.0 million or more in cash consideration, in certain circumstances, we will be required to use a portion of the net cash proceeds of such sale to make an offer to repurchase Convertible Notes at a price equal to the price we would be required to pay for an optional redemption at such time, plus accrued and unpaid interest, if any, up to but excluding the date of repurchase. The Indenture provides for customary events of default. The Indenture contains limited covenants.

Term Loan Facility. As of December 31, 2015, TransAtlantic Albania had $6.1 million outstanding under the Term Loan Facility with Raiffeisen and no availability. As of December 31, 2015, TransAtlantic Albania was in default under the Term Loan Facility for failure to repay $1.1 million due on December 31, 2015. On February 29, 2016, we sold all the equity interests in Stream, the parent of TransAtlantic Albania, to GBC Oil who assumed the Term Loan Facility.

West Promissory Notes. In August 2015, TransAtlantic USA entered into promissory notes (the "Promissory Notes") with each of Mary West CRT 2 LLC and Gary West CRT 2 LLC, shareholders of the Company (collectively, the "Holders"), whereby TransAtlantic USA could borrow up to $1.5 million under each Promissory Note to fund a share repurchase program. The Holders are managed by Randy Rochman, an observer of our board of directors.

On August 21, 2015, TransAtlantic USA borrowed $500,000 under each Promissory Note. Pursuant to the terms of the Promissory Notes, the Holders are granted a first priority lien and security interest in all of our common shares purchased under our share repurchase program. Loans under the Promissory Notes accrue interest at a rate of 9.00% per annum and mature on October 1, 2016. The Promissory Notes are guaranteed by us, and no advances can be made under the notes after December 31, 2015. As of December 31, 2015, we had borrowed $1.0 million under the Promissory Notes and had no availability. The funds were used to purchase shares of our common stock pursuant to our share repurchase program.

Convertible Promissory Note. On December 30, 2015, TransAtlantic USA entered into a $5.0 million draw down convertible promissory note (the "Note") with ANBE Holdings, L.P. ("ANBE"), an entity owned by the children of the Company's chairman and chief executive officer, N. Malone Mitchell, 3rd, and controlled by an entity managed by Mr. Mitchell and his wife. The Note bears interest at a rate of 13.0% per annum and matures on June 30, 2016. On December 30, 2015, the Company borrowed $3.6 million under the Note (the "Initial Advance"). The Initial Advance will be used for general corporate purposes. The Company can request subsequent advances (each, a "Subsequent Advance") under the Note prior to June 15, 2016. Each Subsequent Advance must be in a multiple of $500,000, or if the amount remaining for advance under the Note is less than $500,000, such lesser amount.

Advances under the Note may be converted, at the election of ANBE, any time after the NYSE MKT approves the Company's application to list the additional common shares issuable pursuant to the conversion feature of the Note and prior to the maturity of the Note. The conversion price per common share for each advance is equal to 105% of the closing price of the Company's common shares on the NYSE MKT on the trading date immediately prior to such advance. The conversion price of the Initial Advance is $1.3755 per share.

The Note is a senior unsecured obligation of the Company and is structurally subordinated to all indebtedness of the Company's subsidiaries. Each of the following is an "Event of Default" under the Note:

(i) the Company fails to pay when due any principal of, or interest upon the Note;

(ii) the Note ceases to be a legal, valid, binding agreement enforceable against any party executing the same in accordance with the respective terms thereof or is in any way terminated declared ineffective or inoperative or in any way whatsoever ceases to give or provide the respective rights, interests, remedies, powers or privileges intended to be created thereby;

(iii) the Company (i) applies for or consents to the appointment of a receiver, trustee, inventor, custodian or liquidator of the Company or of all or a substantial part of its assets, as applicable, (ii) is adjudicated as bankrupt or insolvent or files a voluntary petition for bankruptcy or admits in writing that it is unable to pay its debts as they become due, (iii) makes a general assignment for the benefit of creditors, (iv) files a petition or answer seeking reorganization or an arrangement with creditors or to take advantage of any bankruptcy or insolvency laws, or (v) files an answer admitting the material allegations of, or consents to, or defaults in answering, a petition filed against it in any bankruptcy, reorganization or insolvency proceeding, or takes corporate action for the purpose of effecting any of the foregoing; or

(iv) an order, judgment or decree is entered by any court of competent jurisdiction or other competent authority approving a petition seeking reorganization of the Company or appointing a receiver, trustee, inventor or liquidator of any such person, or of all or substantially all of its assets, and such order, judgment or decree continues unstayed and in effect for a period of sixty (60) days.

Contractual Obligations

The following table presents a summary of our contractual obligations at December 31, 2015:

	Payments Due By Year (in thousands)						
	Total	2016	2017	2018	2019	2020	Thereafter
Debt	$ 96,859	$ 41,859	$ 55,000	$ –	$ –	$ –	$ –
Interest	11,934	8,359	3,575	–	–	–	–
Leases	5,595	823	518	446	–	–	3,808
Total	$ 114,388	$ 51,041	$ 59,093	$ 446	$ –	$ –	$ 3,808

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements at December 31, 2015.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Interest Rate Risk

At December 31, 2015, our exposure to interest rate changes related primarily to floating rate borrowings under our Senior Credit Facility. At December 31, 2015, we had $32.1 million in outstanding borrowings under the Senior Credit Facility. The interest we pay on borrowings under the Senior Credit Facility is equal to three-month LIBOR plus 5.00% per annum (5.61% at December 31, 2015). A hypothetical 10% change in the interest rates we pay on the Senior Credit Facility as of December 31, 2015 would result in an increase or decrease in our interest costs of approximately $0.2 million per year.

Foreign Currency Risk

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

The functional currency of our operations in Turkey and Bulgaria is the TRY and the Bulgarian Lev, respectively. The exchange rates used to translate the financial position of our Turkish and Bulgarian operations at December 31, 2015, 2014 and 2013 are shown below:

	Year Ended December 31,		
	2015	2014	2013
New Turkish Lira per $1.00 U.S Dollar	2.9076	2.3189	2.1343
Bulgarian Lev per $1.00 U.S. Dollar	1.7901	1.6084	1.4216

We are also subject to foreign currency exposures as a result of our operations in the other foreign countries in which we operate. We record foreign exchange (gain) loss on our consolidated statements of comprehensive income (loss) as a component of other (expense) income for gains and losses which result from re-measuring transactions and monetary accounts into our functional currency in earnings. The change in foreign exchange (gain) loss is primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the TRY amount if it has not been settled previously. For 2015 and 2014, we recorded a foreign exchange loss of $5.7 million and $6.5 million, respectively. We estimate that a 10% change in the exchange rates would impact our cash balances and our net loss by approximately $0.4 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 Senior Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with BNP Paribas. As a result, TEMI has entered into put contracts with BNP Paribas to hedge the price of oil. The purchased put establishes a lower limit “floor” price. Pursuant to our Senior 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.

We have elected not to designate our derivative financial instruments as hedges for accounting purposes, and accordingly, we record such contracts at fair value and recognize changes in such fair value in current earnings as they occur. We recognize gains and losses related to these contracts on a mark-to-market basis in our consolidated statements of comprehensive income (loss) under the caption "Loss on commodity derivative contracts." Cash settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows. All of our oil derivative contracts are settled based upon Brent crude oil pricing. If commodity prices decrease, this commodity price change could have a positive impact to our earnings. Conversely, if commodity prices increase, this commodity price change could have a negative effect on our earnings. Each derivative contract is evaluated separately to determine its own fair value. During 2015 and 2014, we recorded a net gain on commodity derivative contracts of $27.5 million and $37.5 million, respectively.

On September 14, 2015, October 14, 2015 and November 17, 2015, we unwound all volumes of our crude oil hedge collars and three-way collars for the periods September 14, 2015 through March 31, 2019, October 14, 2015 through March 31, 2019 and December 1, 2015 through March 31, 2019, respectively, and purchased puts with a $50.00 strike price in replacement of the unwound volumes. The puts with a $50.00 strike price were purchased pursuant to the requirements of the Senior Credit Facility at a cost of $4.6 million. The unwound hedges resulted in gross proceeds of $41.8 million, of which $37.2 million was used to repay indebtedness under the Senior Credit Facility.

The following tables summarize our outstanding commodity derivatives contracts with respect to our future oil production as of December 31, 2015:

		Puts		
Type	**Period**	**Quantity (Bbl/day)**	**Weighted Average Minimum Price (per Bbl)**	**Estimated Fair Value of Asset**
				(in thousands)
Put	January 1, 2016—December 31, 2016	808	$ 50.00	3,235
Put	January 1, 2017—December 31, 2017	610	$ 50.00	1,798
Put	January 1, 2018—December 31, 2018	494	$ 50.00	1,292
Put	January 1, 2019—March 31, 2019	443	$ 50.00	280
Total Estimated Fair Value of Asset				$ 6,605

Item 8. Financial Statements and Supplementary Data

See Index to Financial Statements on page F-1.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

As of December 31, 2015, management carried out an evaluation, under the supervision and with the participation of our chief executive officer and chief financial officer, of the effectiveness of our disclosure controls and procedures. Based upon the evaluation, our chief executive officer and chief financial officer concluded that, as of December 31, 2015, our disclosure controls and procedures were 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 (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements, as stated in their reports on pages F-2 and F-3 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2015, we incorporated our Albanian segment within our internal control over financial reporting. Except for incorporating our Albanian segment, there were no additional changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

On March 30, 2016, we entered into an agreement to amend the $11.5 million promissory note (the "Dalea Note") that was originally issued by Dalea to the Company pursuant to the Company's sale of its subsidiaries, Viking International Limited and Viking Geophysical Services Ltd., to a joint venture owned by Dalea and Abraaj Investment Management Limited in June 2012. Pursuant to the agreed upon terms, the Company and Dalea acknowledged that the sale of Dalea's interest in Viking Services B.V. was not intended to trigger acceleration of the repayment of the Dalea Note as long as certain oilfield services were provided by Viking Services B.V. to the Company in Turkey, which services will now be provided pursuant to a master services agreement between Production Solutions International Petrol Arama Hizmetleri Anonim Sirketi ("PSIL") and the Company (the "PSIL MSA"). PSIL is beneficially owned by Dalea Investment Group, LLC, which is controlled by Mr. Mitchell. As a result, the amendment will revise the events triggering acceleration of the repayment of the Dalea Note to the following: (i) a reduction of ownership by Dalea and its affiliates of PSIL to less than 50%; (ii) disposal by Dalea or PSIL of all or substantially all of its assets to any person that does not own a controlling interest in Dalea or PSIL and is not controlled by Mr. Mitchell; (iii) acquisition by any person not controlled by Mr. Mitchell and that does not own a controlling equity interest in Dalea or PSIL of more than 50% of the voting interests of Dalea or PSIL; (iv) termination of the PSIL MSA other than as a result of an uncured default thereunder by the Company (or its subsidiary); (v) default by PSIL under the PSIL MSA, which default is not remedied within a period of 30 days after notice thereof to PSIL; and (vi) insolvency or bankruptcy of PSIL.

In addition, the amendment will reduce the principal amount of the Dalea Note to $8.0 million in exchange for the cancellation of a payable of approximately $3.5 million owed by TransAtlantic Albania to Viking International, which is part of the Delvina Gas Liabilities and for which the Company has indemnified GBC Oil. The amendment will also require Dalea to pledge as security for the Dalea Note the approximately $2.1 million aggregate principal amount of Convertible Notes held by Dalea, including any securities exchanged or converted from the Convertible Notes. The amendment will provide that interest payable to Dalea under the Convertible Notes (or any future securities for which the Convertible Notes are converted or exchanged) will be credited against the outstanding principal balance of the Dalea Note. The maturity date of the Dalea Note was extended to June 13, 2019. The interest rate on the Dalea Note remains at 3.0% per annum and continues to be guaranteed by Mr. Mitchell.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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

Code of Business Conduct

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

Item 11. Executive Compensation

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

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

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

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

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

Item 14. Principal Accountant Fees and Services

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

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of the Report.

1. Reports of Independent Registered Public Accounting Firm
   Consolidated Balance Sheets as of December 31, 2015 and 2014
   Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2015, 2014 and 2013
   Consolidated Statements of Equity for the years ended December 31, 2015, 2014 and 2013
   Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013
   Notes to Consolidated Financial Statements
2. Exhibits required to be filed by Item 601 of Regulation S-K

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

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 30, 2016

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 30, 2016
/S/ WIL F. SAQUETON **Wil F. Saqueton**	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer/Controller)	March 30, 2016
/S/ BOB G. ALEXANDER **Bob G. Alexander**	Director	March 30, 2016
/S/ BRIAN E. BAYLEY **Brian Bayley**	Director	March 30, 2016
/S/ CHARLES J. CAMPISE **Charles J. Campise**	Director	March 30, 2016
/S/ MARLAN W. DOWNEY **Marlan W. Downey**	Director	March 30, 2016
/S/ GREGORY K. RENWICK **Gregory K. Renwick**	Director	March 30, 2016
/S/ MEL G. RIGGS **Mel G. Riggs**	Director	March 30, 2016

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2015 and 2014, and the related consolidated statements of comprehensive income (loss), equity and cash flows for each of the years in the three-year period ended December 31, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015 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 significant debt obligations and non-compliance with certain debt covenants that raise 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, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 30, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 30, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
TransAtlantic Petroleum Ltd.:

We have audited TransAtlantic Petroleum Ltd.'s internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)". TransAtlantic Petroleum Ltd.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. 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.

In our opinion, TransAtlantic Petroleum Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated March 30, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 30, 2016

TRANSATLANTIC PETROLEUM LTD.

Consolidated Balance Sheets
As of December 31, 2015 and 2014
(in thousands of U.S. Dollars, except share data)

	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,480	$ 34,740
Accounts receivable, net		
Oil and natural gas sales	14,169	25,456
Joint interest and other	5,885	19,918
Related party	414	602
Prepaid and other current assets	2,807	5,823
Derivative asset	3,235	12,518
Restricted cash	3,758	–
Assets held for sale	51,511	7,744
Total current assets	89,259	106,801
Property and equipment:		
Oil and natural gas properties (successful efforts method)		
Proved	271,080	323,994
Unproved	31,135	47,137
Equipment and other property	36,708	41,445
	338,923	412,576
Less accumulated depreciation, depletion and amortization	(148,218)	(141,644)
Property and equipment, net	190,705	270,932
Other long-term assets:		
Other assets	4,615	10,753
Note receivable - related party	11,500	11,500
Derivative asset	3,370	19,069
Deferred income taxes	–	1,343
Goodwill	–	6,935
Assets held for sale	–	118,903
Total other assets	19,485	168,503
Total assets	$ 299,449	$ 546,236
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 12,675	$ 19,545
Accounts payable - related party	2,684	13,872
Accrued liabilities	10,583	21,238
Asset retirement obligations	–	323
Loans payable	38,266	34,833
Loan payable - related party	3,593	–
Liabilities held for sale - related party	3,540	11,416
Liabilities held for sale	65,649	47,763
Total current liabilities	136,990	148,990
Long-term liabilities:		
Asset retirement obligations	9,237	10,220
Accrued liabilities	11,940	7,736
Deferred income taxes	27,360	24,946
Loans payable	34,400	80,089
Loan payable - related party	20,600	20,800
Liabilities held for sale	–	41,991
Total long - term liabilities	103,537	185,782
Total liabilities	240,527	334,772
Commitments and contingencies		
Shareholders' equity:		
Common shares, $0.10 par value, 100,000,000 shares authorized; 41,017,777 shares and 40,708,120 shares issued and outstanding as of December 31, 2015 and December 31, 2014, respectively	4,102	4,071
Treasury stock	(970)	–
Additional paid-in-capital	569,365	571,150
Accumulated other comprehensive loss	(121,590)	(79,310)
Accumulated deficit	(391,985)	(284,447)
Total shareholders' equity	58,922	211,464
Total liabilities and shareholders' equity	$ 299,449	$ 546,236

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

Consolidated Statements of Comprehensive Income (Loss)
For the years ended December 31, 2015, 2014 and 2013
(U.S. Dollars and shares in thousands, except per share amounts)

	2015	2014	2013
Revenues:			
Oil and natural gas sales	$ 82,716	$ 136,276	$ 127,270
Sales of purchased natural gas	2,189	2,127	2,581
Other	159	427	976
Total revenues	85,064	138,830	130,827
Costs and expenses:			
Production	12,873	18,193	18,602
Exploration, abandonment and impairment	21,544	19,864	27,333
Cost of purchased natural gas	2,082	2,055	2,247
Seismic and other exploration	370	4,285	14,009
Revaluation of contingent consideration	–	(2,500)	(5,000)
General and administrative	24,138	31,071	29,020
Depreciation, depletion and amortization	37,707	48,594	41,322
Accretion of asset retirement obligations	368	406	508
Total costs and expenses	99,082	121,968	128,041
Operating (loss) income	(14,018)	16,862	2,786
Other income (expense):			
Interest and other expense	(13,077)	(6,044)	(3,929)
Interest and other income	855	1,124	1,340
Gain (loss) on commodity derivative contracts	27,457	37,454	(2,698)
Foreign exchange loss	(5,653)	(6,523)	(9,663)
Total other income (expense)	9,582	26,011	(14,950)
Income (loss) from continuing operations before income taxes	(4,436)	42,873	(12,164)
Current income tax expense	(3,587)	(1,784)	(128)
Deferred income tax expense	(18,642)	(11,875)	(979)
Net (loss) income from continuing operations	(26,665)	29,214	(13,271)
Loss from discontinued operations before income taxes	(97,042)	(750)	(442)
Income tax benefit	16,169	612	–
Net loss from discontinued operations	(80,873)	(138)	(442)
Net (loss) income	(107,538)	29,076	(13,713)
Other comprehensive (loss) income:			
Foreign currency translation adjustment	(42,280)	(14,325)	(36,973)
Comprehensive (loss) income	$ (149,818)	$ 14,751	$ (50,686)
Net (loss) income per common share:			
Basic net income (loss) per common share			
Continuing operations	$ (0.65)	$ 0.77	$ (0.36)
Discontinued operations	$ (1.98)	$ –	$ (0.01)
Weighted average common shares outstanding	40,841	37,829	37,069
Diluted net income (loss) per common share			
Continuing operations	$ (0.65)	$ 0.77	$ (0.36)
Discontinued operations	$ (1.98)	$ –	$ (0.01)
Weighted average common and common equivalent shares outstanding	40,841	38,031	37,069

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

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Equity
For the years ended December 31, 2015, 2014 and 2013
(U.S. Dollars and shares in thousands)

	Common Shares	Treasury Shares	Warrants	Common Shares (at par)	Treasury Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Shareholders' Equity
Balances at December 31, 2012	36,875	–	–	$ 3,687	$ –	$ 537,962	$ (28,012)	$ (299,810)	$ 213,827
Issuance of common shares	351	–	–	35	–	2,465	–	–	2,500
Issuance of restricted stock units	114	–	–	12	–	(12)	–	–	–
Tax withholding on restricted stock units	–	–	–	–	–	(40)	–	–	(40)
Share-based compensation	–	–	–	–	–	1,716	–	–	1,716
Foreign currency translation adjustment	–	–	–	–	–	–	(36,973)	–	(36,973)
Net loss	–	–	–	–	–	–	–	(13,713)	(13,713)
Balances at December 31, 2013	37,340	–	–	$ 3,734	$ –	$ 542,091	$ (64,985)	$ (313,523)	$ 167,317
Issuance of common shares	3,219	–	–	322	–	23,528	–	–	23,850
Contingent payment event	–	–	–	–	–	4,188	–	–	4,188
Issuance of warrants	–	–	233	–	–	–	–	–	–
Issuance of restricted stock units	149	–	–	15	–	(15)	–	–	–
Tax withholding on restricted stock units	–	–	–	–	–	(76)	–	–	(76)
Share-based compensation	–	–	–	–	–	1,434	–	–	1,434
Foreign currency translation adjustment	–	–	–	–	–	–	(14,325)	–	(14,325)
Net income	–	–	–	–	–	–	–	29,076	29,076
Balances at December 31, 2014	40,708	–	233	$ 4,071	$ –	$ 571,150	$ (79,310)	$ (284,447)	$ 211,464
Issuance of common shares	–	–	–	–	–	–	–	–	–
Contingent payment event	–	–	–	–	–	(4,188)	–	–	(4,188)
Issuance of warrants	–	–	466	–	–	–	–	–	–
Issuance of restricted stock units	310	–	–	31	–	1,106	–	–	1,137
Tax withholding on restricted stock units	–	–	–	–	–	(391)	–	–	(391)
Repurchase of treasury stock	–	333	–	–	(970)	–	–	–	(970)
Share-based compensation	–	–	–	–	–	1,688	–	–	1,688
Foreign currency translation adjustment	–	–	–	–	–	–	(42,280)	–	(42,280)
Net loss	–	–	–	–	–	–	–	(107,538)	(107,538)
Balances at December 31, 2015	41,018	333	699	$ 4,102	$ (970)	$ 569,365	$ (121,590)	$ (391,985)	$ 58,922

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

Consolidated Statements of Cash Flows
For the years ended December 31, 2015, 2014 and 2013
(in thousands of U.S. Dollars)

	2015	2014	2013
Operating activities:			
Net (loss) income	$ (107,538)	$ 29,076	$ (13,713)
Adjustment for net loss from discontinued operations	80,873	138	442
Net (loss) income from continuing operations	(26,665)	29,214	(13,271)
Adjustments to reconcile net income to net cash provided by operating activities:			
Share-based compensation	1,688	1,434	1,716
Foreign currency loss	5,910	6,448	8,620
(Gain) loss on commodity derivative contracts	(27,457)	(37,454)	2,698
Cash settlement on commodity derivative contracts	57,076	(2,100)	(3,521)
Amortization on loan financing costs	1,677	1,025	510
Bad debt expense	422	1,487	–
Deferred income tax expense	18,642	11,875	979
Exploration, abandonment and impairment	21,544	19,864	27,333
Depreciation, depletion and amortization	37,707	48,594	41,322
Accretion of asset retirement obligations	368	406	508
Derivative put costs	(4,638)	–	–
Revaluation of contingent consideration	–	(2,500)	(5,000)
Changes in operating assets and liabilities:			
Accounts receivable	18,274	(3,326)	(2,353)
Prepaid expenses and other assets	1,341	(1,777)	(34)
Accounts payable and accrued liabilities	(19,380)	4,734	9,269
Net cash provided by operating activities from continuing operations	86,509	77,924	68,776
Net cash used in operating activities from discontinued operations	(14,483)	(264)	(1,426)
Net cash provided by operating activities	72,026	77,660	67,350
Investing activities:			
Acquisitions, net of cash	–	66	–
Additions to oil and natural gas properties	(22,843)	(107,353)	(94,266)
Additions to equipment and other properties	(3,572)	(6,318)	(10,653)
Restricted cash	(5,261)	(1,917)	(190)
Net cash used in investing activities from continuing operations	(31,676)	(115,522)	(105,109)
Net cash (used in) provided by investing activities from discontinued operations	(12,329)	(1,174)	1,016
Net cash used in investing activities	(44,005)	(116,696)	(104,093)
Financing activities:			
Tax withholding on restricted share units	(391)	(76)	(40)
Treasury stock purchases	(970)	–	–
Loan proceeds	12,378	73,237	66,785
Loan proceeds - related party	3,593	20,800	–
Loan repayment	(54,834)	(28,096)	(29,785)
Loan financing costs	(30)	(2,630)	–
Net cash (used in) provided by financing activities from continuing operations	(40,254)	63,235	36,960
Net cash used in financing activities from discontinued operations	(13,709)	(1,674)	–
Net cash (used in) provided by financing activities	(53,963)	61,561	36,960
Effect of exchange rate on cash flows and cash equivalents	(1,318)	(666)	(2,104)
Net (decrease) increase in cash and cash equivalents	(27,260)	21,859	(1,887)
Cash and cash equivalents, beginning of year	34,740	12,881	14,768
Cash and cash equivalents, end of year	$ 7,480	$ 34,740	$ 12,881
Supplemental disclosures:			
Cash paid for interest	$ 9,522	$ 3,490	$ 3,091
Cash paid for taxes	$ 3,044	$ –	$ 2,387
Supplemental non-cash financing activities:			
Repayment of the Prepayment Agreement	$ 3,043	$ –	$ –
Issuance of common shares for acquisition	$ –	$ 23,850	$ –
Contingent payment event	$ (4,188)	$ 4,188	$ –
Issuance of common shares - amendment to purchase agreement	$ –	$ –	$ 2,500

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

1. General

Nature of operations

TransAtlantic Petroleum Ltd. (together with its subsidiaries, "we," "us," "our," the "Company" or "TransAtlantic") is an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established, yet underexplored petroleum systems, have stable governments, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. We hold interests in developed and undeveloped oil and natural gas properties in Turkey and Bulgaria. As of March 29, 2016, approximately 36% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, our chief executive officer and chairman of our board of directors.

TransAtlantic is a holding company with three operating segments – Turkey, Bulgaria and Albania (presented as assets held for sale). Its assets consist of its ownership interests in subsidiaries that primarily own:

- assets in Turkey;
- assets in Albania that are classified as held for sale; and
- assets in Bulgaria.

Basis of presentation

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

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 of $107.5 million for the year ended December 31, 2015, which includes a net loss from discontinued operations of $80.9 million. At December 31, 2015, the outstanding principal amount of our debt was $96.9 million (excluding liabilities held for sale), and we had a working capital deficit (excluding assets and liabilities held for sale) of $30.1 million.

Due to the significant decline in Brent crude oil prices during 2015, the borrowing base under the Company's senior credit facility (the "Senior Credit Facility") with BNP Paribas (Suisse) SA ("BNP Paribas") and the International Finance Corporation ("IFC") was decreased to $16.6 million effective December 30, 2015. The decline in the borrowing base resulted in a $15.5 million borrowing base deficiency under the Senior Credit Facility as of December 30, 2015.

On December 30, 2015, the lenders granted us a waiver of certain defaults under the Senior Credit Facility that existed as of December 30, 2015, including, among other things, the borrowing base deficiency. The waiver is conditioned upon, among other things, no borrowing base deficiency existing as of March 31, 2016.

As of December 31, 2015, the Company had $32.1 million outstanding under the Senior Credit Facility and no availability and was not in compliance with the current ratio financial covenant in the Senior Credit Facility.

During the first quarter of 2016, we repaid $1.3 million under the Senior Credit Facility, and as of March 30, 2016, we had a borrowing base deficiency of $14.2 million.

We have negotiated a preliminary waiver of the existing defaults under the Senior Credit Facility and an extension of the borrowing base deficiency repayment obligation until at least September 30, 2016. This preliminary waiver and extension is subject to the approval of the lenders' respective credit committees. The lenders have advised us that they will seek credit committee approval of the preliminary waiver and extension in early April 2016. We cannot guarantee that this waiver and extension will be approved by our lenders. Because we are currently in default under the Senior Credit Facility and will be unable to repay the borrowing base deficiency by March 31, 2016, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, could foreclose against the assets securing their borrowings, and we could be forced into bankruptcy or liquidation. In addition, a payment default under the Senior Credit Facility could result in a cross default under our Convertible Notes.

Even if we obtain the funds to repay our borrowing base deficiency, we should need some form of debt restructuring, capital raising effort or asset sale in order to fund our operations and meet our substantial debt service obligations of approximately $41.9 million in 2016 and $55.0 million in 2017. Our management is actively pursuing improving our working capital position and/or restructuring our future debt service obligations in order to remain a going concern for the foreseeable future.

As a result there is substantial doubt regarding our ability to continue as a going concern.

Management believes the going concern assumption to be appropriate for these consolidated 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.

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 in consolidation. During the year ended December 31, 2015, we reclassified certain balance sheet amounts previously reported on our consolidated balance sheet at December 31, 2014 to conform to current year presentation.

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, we recognize the change in a derivative contract's fair value currently in earnings as a component of other income (expense).

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 bot h significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

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

Foreign currency remeasurement and translation

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

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

Oil and natural gas properties

In accordance with the successful efforts method of accounting for oil and natural gas properties, costs of productive wells, developmental dry holes and productive leases are capitalized into appropriate groups of properties based on geographical and geological similarities. Acquisition costs of proved properties are amortized using the unit-of-production method based on total proved reserves, and exploration well costs and additional development costs are amortized using the unit-of-production method based on proved developed reserves. Proceeds from the sale of properties are credited to property costs, and a gain or loss is recognized when a significant portion of an amortization base is sold or abandoned.

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

Equipment and other property

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

Impairment of long-lived assets

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

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

Goodwill

In accordance with ASC 350, *Intangibles-Goodwill and Other* ("ASC 350"), goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise. ASC 350 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. At December 31, 2015, we performed our annual assessment of goodwill and determined it was necessary to perform the two-step goodwill impairment test. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the reporting unit was less than its carrying amount based on our reserves report, dated December 31, 2015. The decline in our Turkey reserves report values was primarily due to the decline in the Brent oil price during the three months ended December 31, 2015. Therefore, we performed step two of the impairment test, which indicated that the entire balance of goodwill was impaired. As a result, we recorded an impairment equal to the carrying amount of goodwill, or $5.5 million, at December 31, 2015 which is included in exploration, abandonment and impairment in the accompanying consolidated statement of comprehensive income (loss) for the year ended December 31, 2015.

Joint interest activities

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

Asset retirement obligations

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

Revenue recognition

Revenue from the sale of crude oil and natural gas is recognized upon delivery to the purchaser when title passes. During the years ended December 31, 2015, 2014 and 2013, we sold $63.0 million, $102.8 million and $87.2 million, respectively, of oil to Türkiye Petrol Rafinerileri A.Ş. ("TUPRAS"), a privately owned oil refinery in Turkey, which represented approximately 74.0%, 74.1% and 66.7% of our total revenues, respectively.

Share-based compensation

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

Income taxes

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

In connection with our acquisition of Amity Oil International Pty Ltd ("Amity") and Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş. ("Petrogas") in August 2010, at December 31, 2013, we recognized a liability due to an uncertain tax position and corresponding asset related to the transfer of Petrogas shares to Amity prior to the acqu isition (see Note 11, “Income taxes”). As the statute of limitations has expired we have reversed this non-current asset and non-current liability, as of December 31, 2015.

As of December 31, 2015, we recorded a $10.1 million liability due to an uncertain tax position related to the unwinding of all of our crude oil hedge collar and three-way contracts, which is included in long-term accrued liabilities on our consolidated balance sheet.

We do not believe there will be any material changes in our unrecognized tax positions over the next twelve months. Our policy is that we recognize interest and penalties accrued on any unrecognized tax positions as a component of income tax expense.

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

Comprehensive income

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

Business combinations

We follow ASC 805, *Business Combinations* (“ASC 805”), and ASC 810-10-65, *Consolidation* (“ASC 810-10-65”). ASC 805 requires most identifiable assets, liabilities, non-controlling interests, and goodwill acquired in a business combination to be recorded at “fair value.” The statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under ASC 805, all business combinations are accounted for by applying the acquisition method. See Note 18, “Acquisitions”.

Per share information

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

4. New accounting pronouncements

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern* (“ASU 2014-15”), an amendment to FASB Accounting Standards Codification (“ASC”) Topic 205, *Presentation of Financial Statements*. This update provides guidance on management’s responsibility in evaluating whether there is a substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. We have adopted ASU 2014-15 for the year ended December 31, 2015. See disclosure in Note 2, “Going concern”.

In April 2015, the FASB issued ASU 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-03"). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. We currently recognize debt issuance costs as assets on our consolidated balance sheet. The recognition and measurement guidance for debt issuance costs are not affected by ASU 2015-03. ASU 2015-03 is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015 and early adoption is permitted. Currently, we do not expect the adoption of ASU 2015-03 to have a material impact on our consolidated financial statements or results of operations.

In July 2015, the FASB issued ASU 2015-11, *Simplifying the Measurement of Inventory* (“ASU 2015-11”), an amendment to ASC Subtopic 330-10. The amendment states that entities should measure inventory at the lower of cost and net realizable value. The amendment does not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. The amendment applies to all other inventory, which includes inventory that is measured using first-in, first-out (FIFO) or average cost. ASU 2015-11 is effective for the fiscal years beginning after December 31, 2016, including interim periods within those fiscal years. We are currently assessing the potential impact of ASU 2015-11 on our consolidated financial statements and results of operations.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 805) Simplifying the Accounting for Measurement-Period Adjustments* ("ASU 2015-16"). ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. The amendments in the update should be applied prospectively to adjustments to provisional amounts that occur after the effective date of ASU 2015-16 with earlier application permitted for financial statements that have not been issued. As of December 31, 2015, we adopted ASU 2015-16 and have disclosed adjustments to our provisional amounts in Note 18, "Acquisitions".

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* ("ASU 2015-17"). ASU 2017-17 requires entities with a classified balance sheet to present all deferred tax assets and liabilities as noncurrent. ASU 2015-17 is effective for annual periods and interim periods in fiscal years beginning after December 15, 2016. As of December 31, 2015, we have adopted ASU 2015-17 and have adjusted the amounts in our consolidated balance sheet as of December 31, 2015 and 2014.

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. 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. At December 31, 2015, we performed our annual assessment of goodwill and determined it was necessary to perform the two-step goodwill impairment test. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of our Turkey reporting unit was less than its carrying amount based on our reserves report dated December 31, 2015. The decline in our Turkey reserves report values was primarily due to the decline in the Brent oil price during the three months ended December 31, 2015. Therefore, we performed step two of the impairment test, which indicated that the entire balance of goodwill was impaired. As a result, we recorded an impairment equal to the carrying amount of goodwill, or $5.5 million, at December 31, 2015. Goodwill was as follows at December 31, 2015 and 2014:

	2015	2014
	(in thousands)	
Goodwill at January 1	$ 6,935	$ 7,535
Foreign exchange effect	(1,404)	(600)
Impairment	(5,531)	–
Goodwill at December 31	$ –	$ 6,935

6. Property and equipment

Oil and natural gas properties

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

	2015	2014
	(in thousands)	
Oil and natural gas properties, proved:		
Turkey	$ 270,591	$ 323,442
Bulgaria	489	552
Total oil and natural gas properties, proved	271,080	323,994
Oil and natural gas properties, unproved:		
Turkey	31,135	43,090
Bulgaria	–	4,047
Total oil and natural gas properties, unproved	31,135	47,137
Gross oil and natural gas properties	302,215	371,131
Accumulated depletion	(139,002)	(132,971)
Net oil and natural gas properties	$ 163,213	$ 238,160

The decline in oil and natural gas properties during the year ended December 31, 2015 was primarily driven by the devaluation of the Turkish Lira ("TRY") versus the U.S. Dollar. For the year ended December 31, 2015, we have recorded foreign currency translation adjustments which reduced oil and natural gas properties and increased accumulated other comprehensive loss within shareholders' equity on our consolidated balance sheet.

At December 31, 2015 and 2014, we excluded $0.7 million and $1.2 million of costs, respectively, from the depletion calculation for development wells in progress.

At December 31, 2015, the capitalized costs of our oil and natural gas properties included $20.0 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and $111.4 million relating to well costs, and additional development costs, which are being amortized by the unit-of-production method using proved developed reserves.

At December 31, 2014, the capitalized costs of our oil and natural gas properties included $29.0 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and $160.8 million relating to well costs, and additional development costs, which are being amortized by the unit-of-production method using proved developed reserves.

Impairments of proved properties and impairment of exploratory well costs

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. The factors used to determine fair value include (Level 3 inputs), but are not limited to, estimates of proved reserves, future commodity prices, the timing and amount of future production and capital expenditures and discount rates commensurate with the risk reflective of the lives remaining for the respective oil and natural gas properties.

Excluding the impairment of goodwill, during the year ended December 31, 2015, we recorded $16.0 million of impairment of proved properties and exploratory well costs which are primarily measured using Level 3 inputs. Of the $16.0 million of impairment of proved properties and exploratory well costs incurred during the year ended December 31, 2015, $5.8 million primarily related to proved property impairments on our Goksu, Molla and Bakuk fields in Turkey where we wrote the properties down to their estimated fair value. The impairment on our Goksu and Molla fields was due to the decline in the Brent oil price and reduction in the reserve volumes.

The remaining charges during the year ended December 31, 2015 were due to $3.7 million related to exploratory well impairment on our Deventci-R2 well in Bulgaria, $3.5 million related to impairment on our Pinar-1 well and $0.7 million related to the South Goksu-1 well, which is part of our joint venture in the Arpatepe field in Turkey. Approximately $4.9 million of the amount impaired was cash spent during the period.

During the year ended December 31, 2014, we recorded $19.9 million in impairment on our proved and unproved properties. Of the $19.9 million, approximately $13.8 million relates to unproved exploratory well impairment on the following wells: $3.5 million related to impairment on the Catak-1 well, $2.8 million related to the Kazanci-5 well, and $7.5 million related to the Bahar-2 side track well.

During the year ended December 31, 2013, we recorded $27.3 million in impairment on our proved and unproved properties, primarily related to $16.0 million of exploratory well impairment, and the remaining amount on impairment of our Senova and Malkara licenses.

Capitalized costs greater than one year

As of December 31, 2015, we had $1.3 million and $2.2 million of exploratory well costs capitalized for the Hayrabolu-10 and Pinar-1 wells, respectively, in Turkey, which we spud in February 2013 and December 2014, respectively. The Hayrabolu-10 and Pinar-1 wells continue to be held for completion.

Equipment and other property

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

	2015	2014
	(in thousands)	
Other equipment	$ 2,378	$ 2,983
Inventory	21,338	23,411
Gas gathering system and facilities	4,798	6,016
Vehicles	400	488
Leasehold improvements, office equipment and software	7,794	8,547
Gross equipment and other property	36,708	41,445
Accumulated depreciation	(9,216)	(8,673)
Net equipment and other property	$ 27,492	$ 32,772

We have reclassified certain prior year costs of equipment and other property to conform to current period presentation.

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, 2015, we excluded $21.3 million of inventory from depreciation, as the inventory had not been placed into service. At December 31, 2014, we excluded $23.4 million of inventory and $3.0 million of software from depreciation as the inventory had not been placed into service.

7. Commodity derivative instruments

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

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

During the years ended December 31, 2015, 2014 and 2013, we recorded a net gain on commodity derivative contracts of $27.5 million, a net gain of $37.5 million and net loss of $2.7 million, respectively.

On September 14, 2015, October 14, 2015 and November 17, 2015, we unwound all volumes of our crude oil hedge collars and three-way collars for the periods September 14, 2015 through March 31, 2019, October 14, 2015 through March 31, 2019 and December 1, 2015 through March 31, 2019, respectively, and purchased puts with a $50.00 strike price in replacement of the unwound volumes. The puts with a $50.00 strike price were purchased pursuant to the requirements of the Senior Credit Facility at a cost of $4.6 million. The unwound hedges resulted in gross proceeds of $41.8 million, of which $37.2 million was used to repay indebtedness under the Senior Credit Facility.

At December 31, 2015, we had outstanding commodity derivative contracts with respect to our future crude oil production as set forth in the tables below:

Fair Value of Derivative Instruments as of December 31, 2015

		Puts		
Type	**Period**	**Quantity (Bbl/day)**	**Weighted Average Minimum Price (per Bbl)**	**Estimated Fair Value of Asset**
				(in thousands)
Put	January 1, 2016— December 31, 2016	808	$ 50.00	3,235
Put	January 1, 2017— December 31, 2017	610	$ 50.00	1,798
Put	January 1, 2018— December 31, 2018	494	$ 50.00	1,292
Put	January 1, 2019— March 31, 2019	443	$ 50.00	280
Total Estimated Fair Value of Asset				$ 6,605

At December 31, 2014, we had outstanding commodity derivative contracts with respect to our future crude oil production as set forth in the tables below:

Fair Value of Derivative Instruments as of December 31, 2014

Type	**Period**	**Quantity (Bbl/day)**	**Weighted Average Minimum Price (per Bbl)**	**Weighted Average Maximum Price (per Bbl)**	**Estimated Fair Value of Asset**
					(in thousands)
Collar	January 1, 2015— December 31, 2015	1,410	$ 85.00	$ 97.25	$ 12,518
					$ 12,518

			Collars		Additional Call	
Type	**Period**	**Quantity (Bbl/day)**	**Weighted Average Minimum Price (per Bbl)**	**Weighted Average Maximum Price (per Bbl)**	**Weighted Average Maximum Price (per Bbl)**	**Estimated Fair Value of Asset**
						(in thousands)
Three-way collar contract	January 1, 2016— December 31, 2016	1,066	$ 85.00	$ 97.25	$ 114.25	$ 7,609
Three-way collar contract	January 1, 2017— December 31, 2017	888	$ 85.00	$ 97.25	$ 114.25	5,748
Three-way collar contract	January 1, 2018— December 31, 2018	726	$ 85.00	$ 97.25	$ 114.25	4,659
Three-way collar contract	January 1, 2019— March 31, 2019	663	$ 85.00	$ 97.25	$ 114.25	1,053
						19,069
Total Estimated Fair Value of Asset						$ 31,587

Balance sheet presentation

The following table summarizes both: (i) the gross fair value of our commodity derivative instruments by the appropriate balance sheet classification even when the commodity derivative instruments are subject to netting arrangements and qualify for net presentation in our consolidated balance sheets at December 31, 2015 and December 31, 2014, and (ii) the net recorded fair value as reflected on our consolidated balance sheets at December 31, 2015 and December 31, 2014.

		As of December 31, 2015		
Underlying Commodity	Location on Balance Sheet	Gross Amount of Recognized Assets	Gross Amount Offset in the Consolidated Balance Sheet	Net Amount of Assets Presented in the Consolidated Balance Sheet
			(in thousands)	
Crude oil	Current assets	$ 3,235	$ –	$ 3,235
Crude oil	Long-term assets	3,370	–	3,370

		As of December 31, 2014		
Underlying Commodity	Location on Balance Sheet	Gross Amount of Recognized Assets	Gross Amount Offset in the Consolidated Balance Sheet	Net Amount of Assets Presented in the Consolidated Balance Sheet
			(in thousands)	
Crude oil	Current assets	$ 12,518	$ –	$ 12,518
Crude oil	Long-term assets	19,069	–	19,069

8. Asset retirement obligations

As part of our development of oil and natural gas properties, we incur asset retirement obligations ("ARO"). Our ARO results from our responsibility to abandon and reclaim our net share of all working interest properties and facilities. At December 31, 2015, the net present value of our total ARO was estimated to be $9.2 million, with the undiscounted value being $15.1 million. Total ARO at December 31, 2015 shown in the table below consists of amounts for future plugging and abandonment liabilities on our wellbores and facilities based on third-party estimates of such costs, adjusted for inflation at a rate of approximately 6.9% per annum for Turkey. These values are discounted to present value using our credit-adjusted risk-free rate of 5.6% per annum for Turkey for the year ended December 31, 2015. The following table summarizes the changes in our ARO for the years ended December 31, 2015 and 2014:

	2015	2014
	(in thousands)	
Asset retirement obligations at beginning of period	$ 10,543	$ 10,896
Change in estimates	385	–
Liabilities settled	–	(373)
Foreign exchange change effect	(2,137)	(899)
Additions	78	513
Accretion expense	368	406
Asset retirement obligations at end of period	9,237	10,543
Less: current portion	–	323
Long-term portion	$ 9,237	$ 10,220

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

9. Loans payable

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

Fixed and floating rate loans	December 31, 2015	December 31, 2014
	(in thousands)	
Convertible Notes	$ 34,400	$ 26,600
Senior Credit Facility	32,075	68,297
Convertible Notes - related party	20,600	20,800
TBNG credit facility	5,192	20,025
ANBE Promissory Note	3,592	–
West Promissory Notes	1,000	–
Loans payable	96,859	135,722
Less: current portion	41,859	34,833
Long-term portion	$ 55,000	$ 100,889

Senior Credit Facility

On May 6, 2014, DMLP, Ltd. ("DMLP"), TransAtlantic Exploration Mediterranean International Pty Ltd ("TEMI"), Talon Exploration, Ltd. ("Talon Exploration"), TransAtlantic Turkey, Ltd. ("TransAtlantic Turkey") and Petrogas (collectively, and together with Amity, the "Borrowers") entered into the Senior Credit Facility with BNP Paribas and IFC. Each of the Borrowers is our wholly owned subsidiary. The Senior Credit Facility is guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide, Ltd. ("TWL") (each, a "Guarantor").

The amount drawn under the Senior Credit Facility may not exceed the lesser of (i) $150.0 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. As of December 31, 2015, the lenders had an aggregate commitment of $40.0 million, with individual commitments of $20.0 million each. On the first day of each fiscal quarter commencing April 1, 2016, the lenders' commitments are subject to reduction in an amount equal to 7.69% of the aggregate commitments in effect on April 1, 2016.

The borrowing base amount is re-determined semi-annually on April 1st and October 1st of each year. The October 2015 redetermination resulted in a $15.5 million borrowing base deficiency under the Senior Credit Facility as of December 30, 2015. The borrowing base was $16.6 million as of December 30, 2015. 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; and
- the debt value which results in the loan life coverage ratio for such calculation date being 1.30 to 1.00.

The Senior Credit Facility matures on the earlier of (i) March 31, 2019, or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual banking case of BNP Paribas 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 banking case prepared by BNP Paribas and the Borrowers. The Senior 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 Senior Credit Facility accrue interest at a rate of three-month LIBOR plus 5.00% per annum (5.61% at December 31, 2015). The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.00% 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 Senior Credit Facility, and (b) 1.00% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Senior 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 BNP Paribas or (b) 5.00% for all other letters of credit.

The Senior 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 Senior Credit Facility, including maintaining the following financial ratios during the four most recently completed fiscal quarters:

- 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 Senior 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 Senior 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) any other non-cash charges (including dry hole expenses and seismic expenses, to the extent such expenses would be capitalized under the "full cost" accounting method), (vii) 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), and (viii) transaction costs, expenses and fees incurred in connection with the negotiation, execution and delivery of the Senior Credit Facility and the related loan documents, 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 Senior Credit Facility, until amounts under the Senior 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, (xiv) open or maintain new deposit, securities or commodity accounts, (xv) use the proceeds from any loan in the territories of any country that is not a member of the World Bank, (xvi) incur any expenditure that is not covered by the projections in the most recent corporate cashflow projection, (xvii) modify its social and environmental action plans as determined in conjunction with IFC, (xviii) enter into any transaction or engage in any activity prohibited by the United Nations Security Council, or (xix) engage in any corrupt, fraudulent, coercive, collusive or obstructive practice.

An event of default under the Senior 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 Senior 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.

Pursuant to the Senior Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with BNP Paribas that hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey. As of December 31, 2015, TEMI had put contracts with BNP Paribas, which hedge the price of oil through March 2019.

At December 31, 2015, we had borrowings of $32.1 million under the Senior Credit Facility, a borrowing base deficiency of $15.5 million, and we were not in compliance with the current ratio financial covenant in the Senior Credit Facility. In December 2015, we were not in compliance with certain covenants under our Senior Credit Facility and the lenders declared an event of default and locked the Borrowers' collection accounts. On December 30, 2015, we entered into a Waiver and Consent Agreement with the lenders whereby the lenders provided a conditional waiver of the defaults including a waiver of cross-default under the Term Loan Facility, and permitted the Borrowers to make certain transfers and withdrawals under the collection accounts. Such waiver included certain conditions, including the following:

(i) The borrowing base deficiency must be repaid by March 31, 2016;

(ii) All monthly hedge settlement proceeds shall be used to pay down debt outstanding;

(iii) Net proceeds from certain asset sales shall be used to prepay loans outstanding under the Senior Credit Facility;

(iv) By June 30, 2016, the lenders shall be granted a security interest over all of the equity interests in Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") and all of the assets or property of TBNG; and

(v) On or before June 30, 2016, all holders of the 13% convertible notes due 2017 ("Convertible Notes") shall either (a) convert their debt interests under the Convertible Notes into equity interests, or (b) agree to extend the maturity of the Convertible Notes to April 1, 2019 or later on substantially identical terms.

In addition, we have negotiated a preliminary waiver of the existing defaults under the Senior Credit Facility and an extension of the borrowing base deficiency repayment obligation until at least September 30, 2016. This preliminary waiver and extension is subject to the approval of the lenders' respective credit committees. The lenders have advised us that they will seek credit committee approval of the preliminary waiver and extension in early April 2016. We cannot guarantee that this waiver and extension will be approved by our lenders.

At March 30, 2016, we had borrowings of $30.8 million under the Senior Credit Facility and a borrowing base deficiency of $14.2 million. We have classified all borrowings under the Senior Credit Facility as short-term debt as of December 31, 2015 due to the uncertainty regarding our ability to comply with the covenants in the Senior Credit Facility for the next twelve months.

Convertible Notes

As of December 31, 2015, we had $55.0 million aggregate principal amount of Convertible Notes outstanding. The Convertible Notes were issued pursuant to an indenture, dated as of February 20, 2015 (the "Indenture"), between us and U.S. Bank National Association, as trustee (the "Trustee"). The Convertible Notes bear interest at a rate of 13.0% per annum and mature on July 1, 2017. The Convertible Notes are convertible at any time, at the election of a holder, into our common shares at a conversion price of $6.80 per share.

TBNG credit facility

TBNG has a fully-drawn credit facility with a Turkish bank. During the fourth quarter of 2015, the facility was amended and now bears interest at a rate of 7.0% per annum and the monthly principal installments were deferred until March 29, 2016. The facility is due by June 29, 2016. The facility may be prepaid without penalty. The facility is secured by a lien on a Turkish real estate property owned by Gundem Turizm Yatirim ve Isletme A.S. ("Gundem"), which is 97.5% beneficially owned by Mr. Mitchell and his children. At December 31, 2015, TBNG had a balance of $5.2 million under the credit facility and no availability.

West Promissory Notes

In August 2015, TransAtlantic USA entered into promissory notes (the "Promissory Notes") with each of Mary West CRT 2 LLC and Gary West CRT 2 LLC, shareholders of the Company (collectively, the "Holders"), whereby TransAtlantic USA could borrow up to $1.5 million under each Promissory Note to fund our share repurchase program. The Holders are managed by Randy Rochman, an observer of our board of directors.

On August 21, 2015, TransAtlantic USA borrowed $500,000 under each Promissory Note. Pursuant to the terms of the Promissory Notes, the Holders are granted a first priority lien and security interest in all of our common shares purchased under our share repurchase program. Loans under the Promissory Notes accrue interest at a rate of 9.00% per annum and mature on October 1, 2016.

The Promissory Notes are guaranteed by us, and no advances can be made under the notes after December 31, 2015. As of December 31, 2015, we had borrowed $1.0 million under the Promissory Notes. The funds were used to purchase shares of our common stock pursuant to our share repurchase program.

ANBE Promissory Note

On December 30, 2015, TransAtlantic USA entered into a $5.0 million draw down convertible promissory note (the "Note") with ANBE Holdings, L.P. ("ANBE"), an entity owned by the children of the Company's chairman and chief executive officer, N. Malone Mitchell, 3rd, and controlled by an entity managed by Mr. Mitchell and his wife. The Note bears interest at a rate of 13.0% per annum and matures on June 30, 2016. On December 30, 2015, the Company borrowed $3.6 million under the Note (the "Initial Advance"). The Initial Advance will be used for general corporate purposes. The Company can request subsequent advances (each, a "Subsequent Advance") under the Note prior to June 15, 2016. Each Subsequent Advance must be in a multiple of $500,000, or if the amount remaining for advance under the Note is less than $500,000, such lesser amount.

Advances under the Note may be converted, at the election of ANBE, any time after the NYSE MKT approves the Company's application to list the additional common shares issuable pursuant to the conversion feature of the Note and prior to the maturity of the Note. The conversion price per common share for each advance is equal to 105% of the closing price of the Company's common shares on the NYSE MKT on the trading date immediately prior to such advance. The conversion price of the Initial Advance is $1.3755 per share.

The Note is a senior unsecured obligations of the Company and is structurally subordinated to all indebtedness of the Company's subsidiaries. Each of the following is an "Event of Default" under the Note:

a) the Company fails to pay when due any principal of, or interest upon, the Note;

b) the Note ceases to be a legal, valid, binding agreement enforceable against any party executing the same in accordance with the respective terms thereof or is in any way terminated declared ineffective or inoperative or in any way whatsoever ceases to give or provide the respective rights, interests, remedies, powers or privileges intended to be created thereby;

c) the Company (i) applies for or consents to the appointment of a receiver, trustee, inventor, custodian or liquidator of Company or of all or a substantial part of its assets, as applicable, (ii) is adjudicated as bankrupt or insolvent or files a voluntary petition for bankruptcy or admits in writing that it is unable to pay its debts as they become due, (iii) makes a general assignment for the benefit of creditors, (iv) files a petition or answer seeking reorganization or an arrangement with creditors or to take advantage of any bankruptcy or insolvency laws, or (v) files an answer admitting the material allegations of, or consents to, or defaults in answering, a petition filed against it in any bankruptcy, reorganization or insolvency proceeding, or takes corporate action for the purpose of effecting any of the foregoing; or

d) an order, judgment or decree is entered by any court of competent jurisdiction or other competent authority approving a petition seeking reorganization of the Company or appointing a receiver, trustee, inventor or liquidator of any such person, or of all or substantially all of its assets, and such order, judgment or decree continues unstayed and in effect for a period of sixty (60) days.

Unsecured lines of credit

Our wholly-owned subsidiaries operating in Turkey are party to unsecured, non-interest bearing lines of credit with a Turkish bank. At December 31, 2015, we had no outstanding borrowings under these lines of credit.

Loan financing costs

We capitalize certain costs in connection with obtaining our borrowings, such as lender's fees and related attorney's fees. These costs are amortized on a straight line basis, which approximates the effective interest method over the term of the loan as a component of interest expense. Loan financing costs, which are included in other assets, totaled approximately $1.6 million and $2.7 million as of December 31, 2015 and 2014, respectively. Amortization of loan financing costs totaled approximately $1.6 million, $1.0 million and $0.5 million during 2015, 2014 and 2013, respectively.

10. Shareholders' equity

November 2014 share issuance

In November 2014, we issued 3,218,641 common shares at a deemed price of $7.41 per common share for the acquisition of Stream (see Note 18, "Acquisitions").

July 2013 share issuance

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

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 12.5%.

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 of approximately $1.1 million and $1.4 million with respect to awards of RSUs was recorded for the years ended December 31, 2015 and 2014, respectively. As of December 31, 2015, we had approximately $1.1 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 1.5 years. The following table sets forth RSU activity for the year ended December 31, 2015:

	Number of RSUs (in thousands)	Weighted Average Grant Date Fair Value Per RSU
Unvested RSUs outstanding at December 31, 2014	223	$ 8.21
Granted	586	5.06
Forfeited	(48)	6.26
Vested	(332)	6.31
Unvested RSUs outstanding at December 31, 2015	429	$ 8.21

Stock option plan

Our Amended and Restated Stock Option Plan (2006) (the "Option Plan") terminated on June 16, 2009. All outstanding awards issued under the Option Plan remained in full force and effect. As of December 31, 2015 and 2014, there were no options outstanding under the Option Plan. All options previously outstanding under the Option Plan had a five-year term.

The fair value of stock options was determined using the Black-Scholes Model and was recognized over the service period of the stock option. All stock options are fully vested; therefore, no share-based compensation expense for stock option awards was recorded for the years ended December 31, 2015, 2014 and 2013. We did not grant any stock options during the years ended December 31, 2015, 2014 and 2013.

Details of stock option activity for the years ended December 31, 2015, 2014 and 2013 are presented below.

	2015		2014		2013	
	Number of Options (in thousands)	Weighted Average Exercise Price Per share	Number of Options (in thousands)	Weighted Average Exercise Price Per share	Number of Options (in thousands)	Weighted Average Exercise Price Per share
Outstanding at beginning of year	–	$ –	–	$ –	16	$ 12.30
Granted	–	–	–	–	–	–
Expired	–	–	–	–	(16)	12.30
Exercised	–	–	–	–	–	–
Outstanding at end of year	–	$ –	–	$ –	–	$ –
Exercisable at end of year	–	$ –	–	$ –	–	$ –

Earnings per share

We account for earnings per share in accordance with ASC Subtopic 260-10, *Earnings Per Share* ("ASC 260-10"). ASC 260-10 requires companies to present two calculations of earnings per share: basic and diluted. Basic earnings per common share for the years ended December 31, 2015, 2014 and 2013 equals net income divided by the weighted average shares outstanding during the periods. Weighted average shares outstanding are equal to the weighted average of all shares outstanding for the period, excluding RSUs. Diluted earnings per common share for the years ended December 31, 2015, 2014 and 2013 are computed in the same manner as basic earnings per common share after assuming the issuance of common shares for all potentially dilutive common share equivalents, which includes stock options, RSUs and warrants, whether exercisable or not. The computation of diluted earnings per common share excluded 8.9 million and 0.8 million antidilutive common share equivalents from the years ended December 31, 2015 and 2013, respectively. There were no antidilutive common share equivalents for the year ended December 31, 2014.

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

(in thousands, except per share amounts)	2015	2014	2013
Net (loss) income from continuing operations	$ (26,665)	$ 29,214	$ (13,271)
Net loss from discontinued operations	$ (80,873)	$ (138)	$ (442)
Basic net (loss) income per common share:			
Shares:			
Weighted average common shares outstanding	40,841	37,829	37,069
Basic net (loss) income per common share:			
Continuing operations	$ (0.65)	$ 0.77	$ (0.36)
Discontinued operations	$ (1.98)	$ –	$ (0.01)
Diluted net (loss) income per common share:			
Shares:			
Weighted average shares outstanding	40,841	37,829	37,069
Dilutive effect of:			
Restricted share units	–	152	–
Convertible notes	–	50	–
Weighted average common and common equivalent shares outstanding	40,841	38,031	37,069
Diluted net (loss) income per common share:			
Continuing operations	$ (0.65)	$ 0.77	$ (0.36)
Discontinued operations	$ (1.98)	$ –	$ (0.01)

Warrants

On December 31, 2014, the Company issued 134,169 common share purchase warrants ("Warrants") to Mr. Mitchell and 23,333 common share purchase warrants to each of Mr. Mitchell's children pursuant to warrant agreements. These Warrants were issued to Mr. Mitchell and his children as shareholders of the entity Gundem, which agreed to pledge its primary asset, Turkish real estate property, in exchange for an extension of the maturity date of a credit agreement between the Company and a Turkish bank. As consideration for the pledge of Turkish real estate property, the independent members of the Company's board of directors approved the issuance of the Warrants to be allocated in accordance with each shareholder's ownership percentage of Gundem. Pursuant to the warrant agreements, the Warrants are immediately exercisable, expire 18 months from the date of the release of the pledge on Turkish real estate property, and entitle the holder to purchase one common share for each Warrant at an exercise price of $5.99 per share.

On each of April 24, 2015 and August 13, 2015, we issued 233,333 Warrants to Mr. Mitchell and certain other related parties as shareholders of Gundem, as consideration for the pledge of Turkish real estate property in exchange for an extension of the maturity of a credit agreement between TBNG and a Turkish bank (See Note 9, "Loans payable"). As consideration for the pledge of the Turkish real estate property, the independent members of the Company's board of directors approved the issuance of the Warrants to be allocated in accordance with each shareholder's ownership percentage of Gundem. The Warrants were issued pursuant to a warrant agreement, whereby the Warrants are immediately exercisable, expire 18 months from the date of the release of the pledge on the Turkish real estate property, and entitle the holder to purchase one common share for each Warrant. The Warrants were issued in April 2015 and August 2015 at an exercise price of $5.65 and $2.99 per share, respectively. For the year ended December 31, 2015, we incurred $0.5 million of compensation expense for these Warrants. The fair value of the Warrants was determined using the Black-Scholes Model.

11. Income taxes

The income tax provision differs from the amount that would be obtained by applying the Bermuda statutory income tax rate of 0% for 2015, 2014 and 2013 to income (loss) from continuing operations for the year as follows:

	2015	2014	2013
	(in thousands except rates)		
Statutory rate	0.00%	0.00%	0.00%
(Loss) income from continuing operations before income taxes	$ (4,436)	$ 42,873	$ (12,164)
Increase (decrease) resulting from:			.
Foreign tax rate differentials	$ 1,676	$ 9,262	$ (1,443)
Uncertain tax position	10,066	1,260	–
Unremitted earnings	11,561	–	–
Derivative contracts	(5,038)	–	–
Change in valuation allowance	3,232	228	982
Expiration of non-capital tax loss carryovers	1,740	1,841	1,367
Other	(1,008)	1,068	201
Total	$ 22,229	$ 13,659	$ 1,107

The components of the net deferred income tax liability at December 31, 2015 and 2014 were as follows:

	2015	2014
	(in thousands)	
Deferred tax assets		
Property and equipment	$ 3,749	$ 4,383
Timing of accruals	344	692
Non-capital loss carryovers	24,098	28,155
Valuation allowance	(27,870)	(27,391)
Total deferred tax assets	321	5,839
Deferred tax liabilities		
Property and equipment	(15,756)	(23,124)
Unremitted earnings	(11,561)	–
Unrealized gains on derivative contracts	–	(6,318)
Timing of accruals	(364)	–
Total deferred tax liabilities	(27,681)	(29,442)
Net deferred tax liabilities	$ (27,360)	$ (23,603)
Components of net deferred tax liabilities		
Non-current assets	$ –	$ 1,343
Non-current liabilities	(27,360)	(24,946)
Net deferred tax liabilities	$ (27,360)	$ (23,603)

We have accumulated losses or resource-related deductions available for income tax purposes in Turkey, Romania, Bulgaria and the United States. As of December 31, 2015, we had non-capital tax losses in Turkey of approximately $96.9 million TRY (approximately $33.3 million), which will begin to expire in 2016; non-capital tax losses in Romania of approximately 7.9 million Romanian New Leu (approximately $1.9 million), which will begin to expire in 2018; non-capital losses in Bulgaria of approximately 12.7 million Bulgarian Lev (approximately $7.2 million), which will begin to expire in 2016; and non-capital tax losses in the United States of approximately $46.9 million, which will begin expiring in 2018. As of December 31, 2015 and 2014, we reflected a valuation allowance of $27.9 million and $27.4 million, respectively, as a reduction of our net operating losses and deferred tax assets.

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

We file income tax returns in the United States, Turkey, Romania, Bulgaria, Morocco and Cyprus, with Turkey being the only jurisdiction with significant amounts of taxes due. Income tax returns filed in Turkey for years before 2011 are no longer subject to examination. The Turkish Ministry of Finance is currently conducting tax audits on two of our Turkish subsidiaries, Amity for the year ended December 31, 2011, and Talon Exploration for the year ended December 31, 2014.

During the year ended December 2015, the Turkish Ministry of Finance completed their audits of Amity, TEMI, and DMLP for the year ended December 31, 2010, and TBNG, for the year ended December 31, 2012.

In connection with our acquisition of Amity and Petrogas in August 2010, at December 31, 2013, we recognized a liability due to an uncertain tax position and corresponding asset related to the transfer of Petrogas shares to Amity prior to the acquisition. As the statute of limitations has expired, we have reversed this non-current asset and non-current liability of $6.1 million, including interest and penalties, as of December 31, 2015.

As of December 31, 2015, we recorded a $10.1 million liability due to an uncertain tax position related to the unwinding of all our crude oil hedge collar and three-way contracts, which is included in long-term accrued liabilities on our consolidated balance sheet.

As of December 31, 2015, there were no material uncertain tax positions for which the total amounts of unrecognized tax benefits will significantly increase or decrease within the next 12 months.

Unremitted Earnings

Our foreign subsidiaries generate earnings that are not subject to Turkish dividend withholding taxes so long as they are permanently reinvested in our operations in Turkey. Pursuant to ASC Topic No. 740-30 (formerly APB 23), undistributed earnings of foreign subsidiaries that are no longer permanently reinvested would become subject to Turkish dividend withholding taxes. Prior to fiscal year 2015, we asserted that the undistributed earnings of our foreign Turkish subsidiaries were permanently reinvested.

Primarily due to the increase in our U.S. debt service obligations resulting from the issuance of the Convertible Notes in the aggregate principal amount of $55.0 million in 2015 (see Note 9, "Loans payable"), management concluded that the ability to access certain amounts of foreign earnings would provide greater flexibility to meet corporate cash flow needs without constraining foreign objectives. Accordingly, in the fourth quarter of fiscal year 2015, we withdrew the permanent reinvestment assertion on $77.1 million of earnings generated by certain of our Turkish foreign subsidiaries through fiscal year 2015. We provided for Turkish dividend withholding taxes on the $77.1 million of undistributed foreign Turkish earnings, resulting in the recognition of a deferred tax liability of approximately $11.6 million.

There is no certainty as to the timing of when such Turkish foreign earnings will be distributed to TWL in whole or in part.

12. Segment information

In accordance with ASC 280, *Segment Reporting* (“ASC 280”), we have three reportable geographic segments: Turkey, Bulgaria and Albania (presented as assets held for sale). Summarized financial information from continuing operations concerning our geographic segments is shown in the following tables:

	Corporate	Turkey	Bulgaria	Total	
		(in thousands)			
For the year ended December 31, 2015					
Total revenues	$ –	$ 85,064	$ –	$ 85,064	
Production	–	12,804	69	12,873	
Exploration, abandonment, and impairment	–	17,778	3,766	21,544	
Cost of purchased gas	–	2,082	–	2,082	
Seismic and other exploration	55	264	51	370	
General and administrative	12,729	11,132	277	24,138	
Depreciation, depletion and amortization	306	37,401	–	37,707	
Accretion of asset retirement obligations	–	350	18	368	
Total costs and expenses	13,090	81,811	4,181	99,082	
Operating (loss) income	(13,090)	3,253	(4,181)	(14,018)	
Interest and other expense	(7,383)	(5,694)	–	(13,077)	
Interest income	354	500	1	855	
Gain on commodity derivative contracts	–	27,457	–	27,457	
Foreign exchange loss	(58)	(5,589)	(6)	(5,653)	
(Loss) income from continuing operations before income taxes	(20,177)	19,927	(4,186)	(4,436)	
Income tax expense	–	(22,229)	–	(22,229)	
Net loss from continuing operations	$ (20,177)	$ (2,302)	$ (4,186)	$ (26,665)	
Total assets at December 31, 2015	$ 14,689	$ 232,648	$ 601	$ 247,938	(1)
Capital expenditures for the year ended December 31, 2015	$ 163	$ 22,262	$ 41	$ 22,466	
For the year ended December 31, 2014					
Total revenues	$ –	$ 138,807	$ 23	$ 138,830	
Production	–	18,059	134	18,193	
Exploration, abandonment, and impairment	–	19,820	44	19,864	
Cost of purchased gas	–	2,055	–	2,055	
Seismic and other exploration	178	4,106	1	4,285	
Revaluation of contingent consideration	–	–	(2,500)	(2,500)	
General and administrative	14,418	14,984	1,669	31,071	
Depreciation, depletion and amortization	124	48,452	18	48,594	
Accretion of asset retirement obligations	–	387	19	406	
Total costs and expenses	14,720	107,863	(615)	121,968	
Operating (loss) income	(14,720)	30,944	638	16,862	
Interest and other expense	(36)	(6,007)	(1)	(6,044)	
Interest income	350	770	4	1,124	
Gain on commodity derivative contracts	–	37,454	–	37,454	
Foreign exchange loss	(4)	(6,497)	(22)	(6,523)	
(Loss) income from continuing operations before income taxes	(14,410)	56,664	619	42,873	
Income tax expense	–	(13,659)	–	(13,659)	
Net (loss) income from continuing operations	$ (14,410)	$ 43,005	$ 619	$ 29,214	
Total assets at December 31, 2014	$ 51,919	$ 363,162	$ 4,675	$ 419,756	(1)
Goodwill at December 31, 2014	$ –	$ 6,935	$ –	$ 6,935	
Capital expenditures for the year ended December 31, 2014	$ 545	$ 109,563	$ 1,393	$ 111,501	
For the year ended December 31, 2013					
Total revenues	$ –	$ 130,701	$ 126	$ 130,827	
Production	5	18,384	213	18,602	
Exploration, abandonment, and impairment	–	27,116	217	27,333	
Cost of purchased gas	–	2,247	–	2,247	

	Corporate	Turkey	Bulgaria	Total
		(in thousands)		
Seismic and other exploration	100	13,909	–	14,009
Revaluation of contingent consideration	–	–	(5,000)	(5,000)
General and administrative	12,685	16,068	267	29,020
Depreciation, depletion and amortization	69	41,196	57	41,322
Accretion of asset retirement obligations	–	475	33	508
Total costs and expenses	12,859	119,395	(4,213)	128,041
Operating (loss) income	(12,859)	11,306	4,339	2,786
Interest and other expense	–	(3,929)	–	(3,929)
Interest income	284	1,056	–	1,340
Loss on commodity derivative contracts	–	(2,698)	–	(2,698)
Foreign exchange (loss) gain	(9)	(9,664)	10	(9,663)
(Loss) income loss from continuing operations before income taxes	(12,584)	(3,929)	4,349	(12,164)
Income tax expense	–	(1,107)	–	(1,107)
Net (loss) income from continuing operations	$ (12,584)	$ (5,036)	$ 4,349	$ (13,271) (1)
Total assets at December 31, 2013	$ 14,070	$ 321,749	$ 10,231	$ 346,050
Goodwill at December 31, 2013	$ –	$ 7,535	$ –	$ 7,535
Capital expenditures for the year ended December 31, 2013	$ 1,003	$ 96,206	$ 2,742	$ 99,951

(1) Excludes assets from our discontinued Albanian and Moroccan operations of $51.5 million, $126.6 million, and $0.5 million at December 31, 2015, 2014 and 2013, respectively.

13. Financial instruments

Interest rate risk

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

Foreign currency risk

We have underlying foreign currency exchange rate exposure. Our currency exposures relate to transactions denominated in the Bulgarian Lev, European Union Euro, Albanian Lek, and TRY. We are also subject to foreign currency exposures resulting from translating the functional currency of our subsidiary financial statements into the U.S. Dollar reporting currency. We have not used foreign currency forward contracts to manage exchange rate fluctuations. At December 31, 2015, we had 32.8 million TRY (approximately $11.3 million) in cash and cash equivalents, which exposes us to exchange rate risk based on fluctuations in the value of the TRY.

Commodity price risk

We are exposed to fluctuations in commodity prices for oil and natural gas. Commodity prices are affected by many factors, including but not limited to, supply and demand. At December 31, 2015 and 2014, 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 TUPRAS, which purchase the majority of our oil and natural gas production. The receivables are not collateralized. To date, we have experienced minimal bad debts and have no allowance for doubtful accounts. The majority of our cash and cash equivalents are held by three financial institutions in the United States and Turkey.

Fair value measurements

Cash and cash equivalents, receivables, notes receivable, accounts payable, accrued liabilities, the Note, the Promissory Notes and the TBNG credit facility were each estimated to have a fair value approximating the carrying amount at December 31, 2015 and 2014 due to the short maturity of those instruments.

The financial assets and liabilities measured on a recurring basis at December 31, 2015 and 2014 consisted of our commodity derivative contracts. Fair values for options are based on counterparty market prices. The counterparties use market standard valuation methodologies incorporating market inputs for volatility and risk free interest rates in arriving at a fair value for each option contract. Prices are verified by us using analytical tools. There are no performance obligations related to the put options purchased to hedge our oil production.

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

At December 31, 2015, the fair values of our Convertible Notes and our Senior Credit Facility were estimated using a discounted cash flow analysis based on unobservable Level 3 inputs, including our own credit risk associated with the loans payable. At December 31, 2014, the carrying value approximated the fair value for the Convertible Notes and the Senior Credit Facility. The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2015:

	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)			
Measured on a recurring basis				
Assets:				
Commodity derivative contracts	$ –	$ 6,605	$ –	$ 6,605
Disclosed but not carried at fair value				
Liabilities:				
Senior Credit Facility	–	–	(30,050)	(30,050)
Convertible notes	–	–	(44,489)	(44,489)
Total	$ –	$ 6,605	$ (74,539)	$ (67,934)

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2014:

	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)			
Measured on a recurring basis				
Assets:				
Commodity derivative contracts	$ –	$ 31,587	$ –	$ 31,587
Disclosed but not carried at fair value				
Liabilities:				
Senior Credit Facility	–	(68,297)	–	(68,297)
Convertible notes	–	(47,400)	–	(47,400)
Total	$ –	$ (84,110)	$ –	$ (84,110)

14. Commitments

Our aggregate annual commitments, other than our loans payable, as of December 31, 2015 were as follows:

	Payments Due By Year						
	Total	2016	2017	2018	2019	2020	Thereafter
	(in thousands)						
Interest	$ 11,934	$ 8,359	$ 3,575	$ –	$ –	$ –	$ –
Leases	5,595	823	518	446	–	–	3,808
Total	$ 17,529	$ 9,182	$ 4,093	$ 446	$ –	$ –	$ 3,808

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

We lease office space in Dallas, Texas, Bulgaria, and Turkey. We also lease apartments in Turkey, as well as operations yards in Turkey. Rent expense for the years ended December 31, 2015, 2014 and 2013 was $1.8 million, $2.2 million and $3.3 million, respectively.

15. Contingencies

Contingencies relating to production leases and exploration permits

Selmo

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

Morocco

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

Aglen

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

Direct Petroleum

In July 2013, we entered into a second amendment (the "Amendment") to the purchase agreement (the "Purchase Agreement") with Direct Petroleum ("Direct"). The Amendment set forth a new obligation to drill and test the Deventci-R2 well by May 1, 2014. We completed the drilling and testing requirements pursuant to the Amendment during April 2014, which resulted in the reversal of a $2.5 million contingent liability recorded in 2011. The reversal is recognized in our consolidated statements of comprehensive income (loss) under the caption "Revaluation of contingent consideration" for the year ended December 31, 2014.

In addition, the Amendment provides that we will issue $7.5 million in common shares if the Deventci-R2 well is a commercial success (as defined in the Purchase Agreement) on or prior to May 1, 2016. We will record any provision for this contingent consideration when it is estimable and probable. As of December 31, 2015, we had not recorded a contingent liability for this contingent consideration.

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

In December 2014, Direct Petroleum LLC ("Direct") filed suit against the Company alleging that it was due liquidated damages of $5.0 million worth of common shares of the Company pursuant to the second amendment of the purchase agreement between the Company and Direct. On March 15, 2016, the Company entered into a settlement agreement pursuant to which we agreed to issue 225,000 common shares of the Company to Direct in exchange for a mutual release of all current and future claims against the other party in connection with the purchase agreement.

Bulgaria

In October 2015, the Bulgarian Ministry of Energy and Economy filed a suit against our subsidiary, Direct Petroleum Bulgaria EOOD ("Direct Bulgaria"), claiming a $200,000 penalty for Direct Bulgaria's alleged failure to fulfill the work program associated with the Aglen exploration permit. Direct Bulgaria received a force majeure recognition in 2012 from the Bulgarian Ministry of Energy and Economy, and the force majeure event has not been rectified. We believe that Direct Bulgaria is not under any obligation to fulfill the work program until the force majeure event is rectified, and continue to vigorously defend this claim.

16. Related party transactions

Equity transactions

On December 31, 2014, the Company issued 134,169 Warrants to Mr. Mitchell and 23,333 Warrants to each of Mr. Mitchell's children pursuant to warrant agreements. These Warrants were issued to Mr. Mitchell and his children as shareholders of the entity Gundem, which agreed to pledge its primary asset, Turkish real estate property, in exchange for an extension of the maturity date of a credit agreement between the Company and a Turkish bank. As consideration for the pledge of Turkish real estate property, the independent members of the Company's board of directors approved the issuance of the Warrants to be allocated in accordance with each shareholder's ownership percentage of Gundem. Pursuant to the warrant agreements, the Warrants are immediately exercisable, expire 18 months from the date of the release of the pledge on Turkish real estate property, and entitle the holder to purchase one common share for each Warrant at an exercise price of $5.99 per share.

On each of April 24, 2015 and August 13, 2015, we issued 233,333 Warrants to Mr. Mitchell and certain other related parties as shareholders of Gundem, as consideration for the pledge of Turkish real estate property in exchange for an extension of the maturity of a credit agreement between TBNG and a Turkish bank (See Note 9, "Loans payable"). As consideration for the pledge of the Turkish real estate property, the independent members of the Company's board of directors approved the issuance of the Warrants to be allocated in accordance with each shareholder's ownership percentage of Gundem. The Warrants were issued pursuant to a warrant agreement, whereby the Warrants are immediately exercisable, expire 18 months from the date of the release of the pledge on the Turkish real estate property, and entitle the holder to purchase one common share for each Warrant. The Warrants issued in April 2015 and August 2015 an exercise price of $5.65 and $2.99 per share, respectively. For the year ended December 31, 2015, we incurred $0.5 million of compensation expense for these Warrants. The fair value of the Warrants was determined using the Black-Scholes Model.

Sale of oilfield services business

On June 13, 2012, we closed the sale of our oilfield services business, which was substantially comprised of our wholly owned subsidiaries Viking International Limited ("Viking International") and Viking Geophysical Services, Ltd. ("Viking Geophysical"), to a joint venture owned by Dalea and funds advised by Abraaj Investment Management Limited for an aggregate purchase price of $168.5 million, consisting of approximately $157.0 million in cash and a $11.5 million promissory note from Dalea (the "Dalea Note"). The Dalea Note was payable five years from the date of issuance or earlier upon the occurrence of certain specified events. The promissory note bears interest at a rate of 3.0% per annum and is guaranteed by Mr. Mitchell. See Note 19, "Subsequent events" for additional information.

Service transactions

Effective May 1, 2008, we entered into a service agreement, as amended (the "Service Agreement"), with Longfellow Energy, LP ("Longfellow"), Viking Drilling LLC ("Viking Drilling"), MedOil Supply, LLC and Riata Management, LLC ("Riata Management"). Mr. Mitchell and his wife own 100% of Riata Management. In addition, Mr. Mitchell, his wife and his children indirectly own 100% of Longfellow. Riata Management owns 100% of MedOil Supply, LLC. Dalea owns 85% of Viking Drilling. Under the terms of the

Service Agreement, we pay, or are paid, for the actual cost of the services rendered plus the actual cost of reasonable expenses on a monthly basis.

Effective January 1, 2011, our wholly owned subsidiary, TEMI, entered into an accommodation agreement under which it leased rooms, flats and office space at a facility owned by Gundem. Under the accommodation agreement, TEMI leases six rooms and pays the TRY equivalent of $6,000 per month.

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

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

On March 3, 2016, Mr. Mitchell closed a transaction whereby he sold his interest in Viking Services B.V., the beneficial owner of Viking International, VOS and Viking Geophysical, to a third party. As part of the transaction, Mr. Mitchell acquired certain equipment used in the performance of stimulation, wireline, workover and similar services, which equipment will be owned and operated by a new entity, Production Solutions International Petrol Arama Hizmetleri Anonim Sirketi ("PSIL"). PSIL is beneficially owned by Dalea Investment Group, LLC, which is controlled by Mr. Mitchell. Consequently, on March 3, 2016, TEMI entered into a master services agreement (the "PSIL MSA") with PSIL on substantially similar terms to the Company's current master services agreements with Viking International, VOS and VGS. Pursuant to the PSIL MSA, PSIL will perform the Services on behalf of TEMI and its affiliates. The master services agreements with each of Viking International, VOS and Viking Geophysical will remain in effect through the remainder of the five-year term of the agreements.

On April 5, 2013 (the "First Floor Commencement Date"), TransAtlantic USA entered into an office lease with Longfellow to lease approximately 4,700 square feet of additional corporate office space in Addison, Texas. The initial lease term commenced on the First Floor Commencement Date and expires five years after the First Floor Commencement Date, unless earlier terminated in accordance with the lease. For the first year of the lease, TransAtlantic USA will pay monthly rent of $7,533 to Longfellow plus utilities, real property taxes and liability insurance.

On March 26, 2014, our wholly owned subsidiaries, TEMI and TBNG, entered into an equipment yard services agreement effective as of April 1, 2014 with Viking International for services related to the use of oilfield equipment yards located in Diyarbaki, Tekirdag and Muratli, Turkey. The initial term of the agreement is for twelve months, and the term of the agreement renews automatically for additional twelve-month periods unless earlier terminated. During the initial term, TEMI will pay monthly services fees of $17,250 to Viking International for services related to the use of Diyarbakir equipment yard, and TBNG will pay monthly service fees of $17,250 to Viking International for services related to the use of Tekirdag and Muratli equipment yards.

For the years ended December 31, 2015 and 2014, we incurred capital and operating expenditures of $20.0 million and $96.4 million, respectively, related to our various related party agreements.

Debt transactions

Between December 2014 and February 2015, we sold $55.0 million of convertible notes in a non-brokered private placement, which were exchanged for the Convertible Notes on February 20, 2015. Dalea purchased $2.0 million of the notes; trusts benefitting Mr. Mitchell's four children each purchased $2.0 million of the notes; Pinon Foundation, a non-profit charitable organization directed by Mr. Mitchell's spouse, purchased $10.0 million of the notes; the three children of Brian Bailey, a director of the Company, each purchased $100,000 of the notes; Wil Saqueton, the Company's vice president and chief financial officer, purchased $100,000 of the notes; Matthew McCann, the Company's former general counsel and corporate secretary, purchased $200,000 of the notes; and a trust benefitting Barbara and Terry Pope, Mr. Mitchell's sister-in-law and brother-in-law, purchased $200,000 of the notes.

ANBE Promissory Note

On December 30, 2015, TransAtlantic USA entered into the $5.0 million Note with ANBE, an entity owned by the children of the Company's chairman and chief executive officer, N. Malone Mitchell, 3rd, and controlled by an entity managed by Mr. Mitchell and his wife. The Note bears interest at a rate of 13.0% per annum and matures on June 30, 2016. On December 30, 2015, the Company borrowed the Initial Advance of $3.6 million under the Note. The Initial Advance will be used for general corporate purposes. The Company can request Subsequent Advances under the Note prior to June 15, 2016. Each Subsequent Advance must be in a multiple of $500,000, or if the amount remaining for advance under the Note is less than $500,000, such lesser amount.

Advances under the Note may be converted, at the election of ANBE, any time after the NYSE MKT approves the Company's application to list the additional common shares issuable pursuant to the conversion feature of the Note and prior to the maturity of the Note. The conversion price per common share for each advance is equal to 105% of the closing price of the Company's common shares on the NYSE MKT on the trading date immediately prior to such advance. The conversion price of the Initial Advance is $1.3755 per share.

The Note is a senior unsecured obligations of the Company and is structurally subordinated to all indebtedness of the Company's subsidiaries. Each of the following is an "Event of Default" under the Note:

a) the Company fails to pay when due any principal of, or interest upon, the Note;

b) the Note ceases to be a legal, valid, binding agreement enforceable against any party executing the same in accordance with the respective terms thereof or is in any way terminated declared ineffective or inoperative or in any way whatsoever ceases to give or provide the respective rights, interests, remedies, powers or privileges intended to be created thereby;

c) the Company (i) applies for or consents to the appointment of a receiver, trustee, inventor, custodian or liquidator of Company or of all or a substantial part of its assets, as applicable, (ii) is adjudicated as bankrupt or insolvent or files a voluntary petition for bankruptcy or admits in writing that it is unable to pay its debts as they become due, (iii) makes a general assignment for the benefit of creditors, (iv) files a petition or answer seeking reorganization or an arrangement with creditors or to take advantage of any bankruptcy or insolvency laws, or (v) files an answer admitting the material allegations of, or consents to, or defaults in answering, a petition filed against it in any bankruptcy, reorganization or insolvency proceeding, or takes corporate action for the purpose of effecting any of the foregoing; or

d) an order, judgment or decree is entered by any court of competent jurisdiction or other competent authority approving a petition seeking reorganization of the Company or appointing a receiver, trustee, inventor or liquidator of any such person, or of all or substantially all of its assets, and such order, judgment or decree continues unstayed and in effect for a period of sixty (60) days.

Other related party transactions

During the year ended December 31, 2014, we incurred $60,000 of geology consulting services from Roxanna Oil Company, a private oil and natural gas exploration and production company ("Roxanna"). One of our directors is the chairman of the board of Roxanna.

The following table summarizes related party accounts receivable and accounts payable as of December 31, 2015 and December 31, 2014:

	2015	2014
	(in thousands)	
Related party accounts receivable:		
Viking International master services agreement	$ 220	$ 355
Riata Management Service Agreement	194	159
Dalea Note	–	88
Total related party accounts receivable	$ 414	$ 602
Related party accounts payable:		
Viking International master services agreement	$ 2,300	$ 12,138
Riata Management Service Agreement	384	1,734
Total related party accounts payable	$ 2,684	$ 13,872

17. Discontinued operations

Discontinued operations in Albania

On November 16, 2015, we decided to launch a marketing process for our Albanian assets and operations. As of December 31, 2015 we have classified our Albania segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented.

In February 2016, we sold all of the outstanding equity in Stream to GBC Oil Company Ltd. ("GBC Oil") in exchange for (i) the future payment of $2.3 million to Raiffeisen to pay down the Term Loan Facility dated as of September 17, 2014 between Stream's wholly-owned subsidiary, TransAtlantic Albania, and Raiffeisen, and (ii) the assumption of $29.2 million of liabilities owed by Stream, consisting of $23.1 million of accounts payable and accrued liabilities and $6.1 million of debt. TransAtlantic Albania owns all of our former Albanian assets and operations. In addition, GBC Oil issued us a warrant pursuant to which we have the option to acquire up to 25% of the fully diluted equity interests in TransAtlantic Albania for nominal consideration at any time on or before March 1, 2019. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and $12.9 million of associated liabilities to Delvina Gas Company Ltd. ("Delvina Gas"), our newly formed, wholly-owned subsidiary, to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. In addition, we agreed to indemnify GBC Oil and Stream for the $12.9 million of liabilities related to the Delvina gas operations.

An impairment charge of $73.0 million was recorded to write down the net book value of the assets held for sale to their fair value as of December 31, 2015. The assumptions used in our assessment of fair value included the transaction discussed above with GBC Oil.

Discontinued operations in Morocco

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

The assets and liabilities held for sale at December 31, 2015 and 2014 were as follows:

	Albania	Morocco	Total Held for Sale
		(in thousands)	
For the year ended December 31, 2015			
Assets			
Cash	$ 1,201	$ 16	$ 1,217
Other current assets	1,853	11	1,864
Property and equipment, net	48,430	–	48,430
Total current assets held for sale	$ 51,484	$ 27	$ 51,511
Liabilities			
Accounts payable and other accrued liabilities	$ 37,888	$ 6,352	$ 44,240
Accounts payable - related party	3,540	–	3,540
Loans payable	6,123	–	6,123
Loans payable - related party	–	–	–
Deferred tax liability	15,286	–	15,286
Total current liabilities held for sale	$ 62,837	$ 6,352	$ 69,189
For the year ended December 31, 2014			
Assets			
Cash	$ 392	$ 16	$ 408
Other current assets	7,324	12	7,336
Total current assets held for sale	7,716	28	7,744
Property and equipment, net	118,903	–	118,903
Total assets held for sale	$ 126,619	$ 28	$ 126,647
Liabilities			
Accounts payable and accrued liabilities	$ 29,862	$ 6,928	$ 36,790
Accounts payable - related party	4,616	–	4,616
Loans payable	10,973	–	10,973
Loans payable - related party	6,800	–	6,800
Total current liabilities held for sale	52,251	6,928	59,179
Accrued liabilities	5,433	–	5,433
Loans payable	5,103	–	5,103
Deferred tax liability	31,455	–	31,455
Total long-term liabilities held for sale	41,991	–	41,991
Total liabilities held for sale	$ 94,242	$ 6,928	$ 101,170

Loans Payable

As of the dates indicated, TransAtlantic Albania's third-party debt consisted of the following:

Fixed and floating rate loans	December 31, 2015	December 31, 2014
	(in thousands)	
Term Loan Facility	$ 6,123	$ 10,453
Viking International note - related party	–	6,800
Prepayment Agreement	–	3,043
Shareholder loan	–	2,580
Loans payable	$ 6,123	$ 22,876

Term Loan Facility

TransAtlantic Albania was a party to a Term Loan Facility (the "Term Loan Facility") with Raiffeisen Bank Sh.A. ("Raiffeisen").The loan matures on December 31, 2016 and bears interest at the rate of LIBOR plus 5.5%, with a minimum interest rate of 7.0%.

TransAtlantic Albania is required to pay 1/16th of the total commitment each quarter on the last business day of each of March, June, September and December each year. The loan is guaranteed by TransAtlantic Albania's parent company, Stream. TransAtlantic Albania may prepay the loan at its option in whole or in part, subject to a 3.0% penalty plus breakage costs. The Term Loan Facility is secured by substantially all of the assets of TransAtlantic Albania.

Under the Term Loan Facility, TransAtlantic Albania may not declare or pay any dividends on any of TransAtlantic Albania's common shares without the consent of the lender, except, provided that no default has occurred and is continuing under the Term Loan Facility, TransAtlantic Albania may make payments to Stream from excess cash flow to cover the administrative overhead of Stream, including the salary and related employment costs of any employee, officer or director of Stream, up to a total limit in any three-month period of $500,000.

Pursuant to the terms of the Term Loan Facility, until amounts under the Term Loan Facility are repaid, TransAtlantic Albania may not, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of TransAtlantic Albania to create any liens, (iii) enter into any amalgamation, demerger, merger, or corporate reconstruction or any joint venture or partnership agreement, (iv) incorporate any company as a subsidiary, (v) dispose of any asset, (vi) declare or pay any dividends to shareholders, (vii) enter into a sale and leaseback arrangement, (viii) make any substantial change to the general nature or scope of its business from that carried on at the date of the Term Loan Facility, (ix) use, deposit, handle, store produce, release or dispose of dangerous materials, (x) make any loans or grant any credit, and (xi) cancel, terminate amend or waive any default under any export contract or allow any buyer to do the same.

In addition, the Term Loan Facility contains financial covenants that require TransAtlantic Albania to maintain as of the end of each fiscal year: (i) earnings before interest, taxes, depreciation and amortization ("EBITDA") of not less than $10.0 million; (ii) an outstanding loan principal of no more than twice its EBITDA; and (iii) EBITDA of at least ten times greater than its accrued interest, commission, fees, discounts, prepayment fees, premiums, charges and other finance payments.

An event of default under the Term Loan 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, upon the occurrence of a change of control of TransAtlantic Albania, TransAtlantic Albania is required to notify Raiffeisen, and Raiffeisen would have the option to cancel loan commitments and accelerate all outstanding loans and other amounts payable. A change of control is defined under the Term Loan Facility as Stream ceasing to hold more than 75% of the shares in the issued share capital of TransAtlantic Albania carrying the right to vote.

Stream must, upon the request of Raiffeisen when TransAtlantic Albania's predicted expenditures exceed its predicted revenues for any period, inject cash into Stream by means of equity loan or other method acceptable to Raiffeisen to the extent necessary to remedy the cashflow shortfall or repay the total amount outstanding under the Term Loan Facility.

As of December 31, 2015, TransAtlantic Albania had $6.1 million outstanding under the Term Loan Facility and no availability. As of December 31, 2015, TransAtlantic Albania was in default under the Term Loan Facility for failure to repay $1.1 million due on December 31, 2015. On February 29, 2016, we sold all the equity interest in Stream, the parent company of TransAtlantic Albania to GBC Oil, who assumed the Term Loan Facility.

Prepayment Agreement

Stream and TransAtlantic Albania were parties to the prepayment agreement (the "Prepayment Agreement") with Trafigura PTE Ltd ("Trafigura"). In October 2013, Stream received a $7.0 million prepayment under the Prepayment Agreement. The prepayment was repaid by Stream's delivery of oil to Trafigura in accordance with an oil sales contract between Stream and Trafigura and bore interest at a rate equal to LIBOR plus 6% (6.43% at December 31, 2015). On October 30, 2015, Stream repaid the Prepayment Agreement in full, and the agreement was terminated.

Viking International note

On September 16, 2014, Stream issued to Viking International a note in the principal amount of $6.8 million. The note was amended monthly to evidence additional advances. On March 12, 2015, we repaid the note in full.

Shareholder loan

In March 2014, Stream borrowed CAD $3.0 million from a shareholder of Stream. The loan bore interest at a fixed rate of 10.0% per annum, calculated and compounded monthly. On January 6, 2015, we repaid the shareholder loan in full with net proceeds from our private placement of Convertible Notes.

Our operating results from discontinued operations for the years ended December 31, 2015, 2014 and 2013 are summarized as follows:

	Albania	Morocco	Total
		(in thousands)	
For the year ended December 31, 2015			
Total revenues	$ 8,565	$ –	$ 8,565
Production and transportation expense	11,615	–	11,615
Exploration, abandonment and impairment	86,577	–	86,577
Total other costs and expenses	9,229	5	9,234
Total other income	1,819	–	1,819
Loss before income taxes	$ (97,037)	$ (5)	$ (97,042)
Income tax benefit	16,169	–	16,169
Loss from discontinued operations	$ (80,868)	$ (5)	$ (80,873)
For the year ended December 31, 2014			
Total revenues	$ 1,898	$ –	$ 1,898
Total costs and expenses	2,984	20	3,004
Total other income	356	–	356
Loss before income taxes	$ (730)	$ (20)	$ (750)
Income tax benefit	612	–	612
Loss from discontinued operations	$ (118)	$ (20)	$ (138)
For the year ended December 31, 2013			
Total revenues	$ –	$ –	$ –
Total costs and expenses	–	505	505
Total other income	–	63	63
Loss before income taxes	$ –	$ (442)	$ (442)
Income tax benefit	–	–	–
Loss from discontinued operations	$ –	$ (442)	$ (442)

18. Acquisitions

Stream

On November 18, 2014, we acquired Stream in exchange for (i) 3.2 million of our common shares issued at closing, and (ii) an additional 0.6 million of our common shares issuable if certain conditions are met (at a deemed price of $7.41 per common share). We engaged independent valuation experts to assist in the determination of the fair value of the assets and liabilities acquired in the acquisition. We have completed our assessment of the assets acquired and liabilities assumed, and the values are presented below. The following tables summarize the consideration paid in the acquisition and the final amounts of assets acquired and liabilities assumed that have been recognized at the acquisition date:

		(in thousands)
Consideration:		
Issuance of 3,218,641 common shares	$	23,850
Fair value of total consideration	$	23,850
Acquisition-Related Costs:		
Included in general and administrative expenses on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2014	$	1,129

Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed at Acquisition:		
Assets:		
Cash	$	66
Accounts receivable		6,672
Other current assets		1,418
Total current assets		8,156
Oil and natural gas properties:		
Proved properties		99,927
Unproved properties		12,854
Equipment and other property		2,386
Total oil and natural gas properties and other equipment		115,167
Total assets		123,323
Liabilities:		
Accounts payable		20,673
Accounts payable - related party		2,820
Other current liabilities		13,395
Viking International note - related party		6,800
Loans payable - current		11,732
Other non-current liabilities		5,036
Loans payable - non-current		6,123
Asset retirement obligations		827
Deferred income taxes		32,067
Total liabilities		99,473
Total identifiable net assets	$	23,850

During 2015, we were notified that the Albania government may seek to recover approximately $4.9 million in contractual obligations under our Delvina exploration work program. We have recorded $4.9 million in accrued liabilities associated with the acquisition of Stream related to this contractual work program liability.

As of and for the year ended December 31, 2015, we have recorded the following purchase accounting adjustments, as allowed under ASU 2015-16: (i) reversed the $4.2 million of contingent shares as a result of not achieving the contingent share event within the prescribed period, (ii) increased our equipment and oil inventory by $2.5 million based on more accurate values, and (iii) increased our accrued liabilities by a net $3.3 million due to better estimates. These amounts have been adjusted in our December 31, 2015 consolidated balance sheet and, on a net basis, reduced our unproved property balance.

The results of operations of Stream are included in our consolidated statement of comprehensive income (loss) beginning November 18, 2014 and have been classified as discontinued operations for the year ended December 31, 2015. The revenues and expenses of Stream included in our consolidated statement of comprehensive income (loss) for the year ended December 31, 2014 were:

	Revenue	Loss
	(in thousands)	
Actual from November 18, 2014 through December 31, 2014	$ 1,898	$ (118)

19. Subsequent events

Sale of Albania Oil Operations

In February 2016, we sold all of the outstanding equity in Stream to GBC Oil in exchange for (i) the future payment of $2.3 million to Raiffeisen to pay down the Term Loan Facility dated as of September 17, 2014 between TransAtlantic Albania and Raiffeisen, and (ii) the assumption of $29.2 million of liabilities owed by Stream, consisting of $23.1 million of accounts payable and accrued liabilities and $6.1 million of debt. TransAtlantic Albania owns all of our former Albanian assets and operations. In addition, GBC Oil issued us a warrant pursuant to which we have the option to acquire up to 25% of the fully diluted equity interests in TransAtlantic Albania for nominal consideration at any time on or before March 1, 2019. Prior to the sale of Stream to GBC Oil, TransAtlantic Albania entered into an assignment and assumption agreement pursuant to which TransAtlantic Albania will assign its Delvina natural gas assets and $12.9 million of associated liabilities (the “Delvina Gas Liabilities”) to Delvina Gas, our newly formed, wholly-owned subsidiary, to be effective immediately upon receipt of required contractual consents. There is no assurance that we will be able to obtain the required contractual consents. In addition, we agreed to indemnify GBC Oil and Stream for the Delvina Gas Liabilities. We are currently negotiating a joint venture with a third party for the purchase of a portion of Delvina Gas. There is no assurance that we will be able to complete a joint venture for the purchase of a portion of Delvina Gas.

Dalea Promissory Note Modifications

On March 30, 2016, we entered into an agreement to amend the Dalea Note. Pursuant to the agreed upon terms, the Company and Dalea acknowledged that the sale of Dalea’s interest in Viking Services B.V. was not intended to trigger acceleration of the repayment of the Dalea Note as long as certain oilfield services were provided by Viking Services B.V. to the Company in Turkey, which services will now be provided pursuant to the PSIL MSA. PSIL is beneficially owned by Dalea Investment Group, LLC, which is controlled by Mr. Mitchell. As a result, the amendment will revise the events triggering acceleration of the repayment of the Dalea Note to the following: (i) a reduction of ownership by Dalea and its affiliates of PSIL to less than 50%; (ii) disposal by Dalea or PSIL of all or substantially all of its assets to any person that does not own a controlling interest in Dalea or PSIL and is not controlled by Mr. Mitchell; (iii) acquisition by any person not controlled by Mr. Mitchell and that does not own a controlling equity interest in Dalea or PSIL of more than 50% of the voting interests of Dalea or PSIL; (iv) termination of the PSIL MSA other than as a result of an uncured default thereunder by the Company (or its subsidiary); (v) default by PSIL under the PSIL MSA, which default is not remedied within a period of 30 days after notice thereof to PSIL; and (vi) insolvency or bankruptcy of PSIL.

In addition, the amendment will reduce the principal amount of the Dalea Note to $8.0 million in exchange for the cancellation of a payable of approximately $3.5 million owed by TransAtlantic Albania to Viking International, which is part of the Delvina Gas Liabilities and for which the Company has indemnified GBC Oil. The amendment will also require Dalea to pledge as security for the Dalea Note the approximately $2.1 million aggregate principal amount of Convertible Notes held by Dalea, including any securities exchanged or converted from the Convertible Notes. The amendment will provide that interest payable to Dalea under the Convertible Notes (or any future securities for which the Convertible Notes are converted or exchanged) will be credited against the outstanding principal balance of the Dalea Note. The maturity date of the Dalea Note was extended to June 13, 2019. The interest rate on the Dalea Note remains at 3.0% per annum and continues to be guaranteed by Mr. Mitchell.

Supplemental Information
(unaudited)

Supplemental quarterly financial data (unaudited)

The following table summarizes results for each of the four quarters in the years ended December 31, 2015 and 2014 (1).

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands, except per share data)			
For the year ended December 31, 2015:				
Revenues	$ 25,757	$ 25,053	$ 18,337	$ 15,917
Net (loss) income from continuing operations	(4,023)	(5,689)	15,633	(32,586)
Net loss from discontinued operations	(1,471)	(1,561)	(10,731)	(67,110)
Net (loss) income	(5,494)	(7,250)	4,902	(99,696)
Comprehensive loss	(29,113)	(12,167)	(16,841)	(91,697)
Basic and diluted net (loss) income per common share from continuing operations	$ (0.10)	$ (0.14)	$ 0.38	$ (0.80)
Basic and diluted net loss per common share from discontinuing operations	$ (0.04)	$ (0.04)	$ (0.26)	$ (1.65)
Basic and diluted net (loss) income per common share	$ (0.13)	$ (0.18)	$ 0.12	$ (2.45)
For the year ended December 31, 2014:				
Revenues	$ 33,646	$ 41,061	$ 36,077	$ 28,046
Net income from continuing operations	3,993	1,437	8,313	15,471
Net loss from discontinued operations	(20)	–	–	(118)
Net income (loss)	3,973	1,437	8,313	15,353
Comprehensive income (loss)	678	6,529	(4,343)	11,887
Basic and diluted net (loss) income per common share from continuing operations	$ 0.11	$ 0.04	$ 0.22	$ 0.40
Basic and diluted net loss per common share from discontinuing operations	$ (0.00)	$ –	$ –	$ (0.00)
Basic and diluted net income (loss) per common share	$ 0.11	$ 0.04	$ 0.22	$ 0.39

(1) The sum of the individual quarterly net (loss) income amounts per share may not agree with year-to-date net (loss) income 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.

During the fourth quarter of 2015, we identified an error related to our deferred tax liability and deferred tax benefit 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 a decrease to our net loss of $4.7 million for each of the three and nine months ended September 30, 2015. This immaterial error was corrected in our third quarter of 2015 results of operations.

Supplemental oil and natural gas reserves information (unaudited)

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

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

Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. We engaged DeGolyer & MacNaughton to prepare our reserves estimates in Turkey, Albania and Bulgaria. These estimates comprise 100% of our estimated proved reserves (by volume) at December 31, 2015.

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

All of our proved reserves are located in Turkey and Albania, and all prices are held constant in accordance with SEC rules. As of December 31, 2015, we have classified our Albania segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented.

Oil and natural gas prices used to estimate reserves were computed by applying the un-weighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 2015, 2014 and 2013. The oil and natural gas prices used to estimate reserves are shown in the table below.

	12-Month Average Price	
	Oil per (Bbl)	**Natural Gas per (Mcf)**
Turkey		
2015	$ 48.65	$ 7.65
2014	$ 94.53	$ 8.71
2013	$ 102.07	$ 9.92
Albania		
2015	$ 38.77	$ 7.37
2014	$ 69.55	$ 10.00

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

Disclosure of reserves quantities

	Turkey	Albania(1)	Total
		Oil (Mbbls)	
Total proved reserves			
December 31, 2012	9,520	–	9,520
Extensions and discoveries	1,563	–	1,563
Revisions of previous estimates	(436)	–	(436)
Sales volumes	(933)	–	(933)
December 31, 2013	9,714	–	9,714
Acquisitions	–	14,296	14,296
Extensions and discoveries	4,740	–	4,740
Revisions of previous estimates	1,254	–	1,254
Sales volumes	(1,303)	(36)	(1,339)
December 31, 2014	14,405	14,260	28,665
Extensions and discoveries	362	–	362
Revisions of previous estimates	(2,532)	(9,771)	(12,303)
Sales volumes	(1,420)	(231)	(1,651)
December 31, 2015	10,815	4,258	15,073
Proved developed reserves			
December 31, 2013:			
Proved developed producing	4,540	–	4,540
Proved developed non-producing	335	–	335
Total	4,875	–	4,875
December 31, 2014:			
Proved developed producing	6,153	4,630	10,783
Proved developed non-producing	704	9,270	9,974
Total	6,857	13,900	20,757
December 31, 2015:			
Proved developed producing	4,382	2,096	6,478
Proved developed non-producing	1,216	1,989	3,205
Total	5,598	4,085	9,683
Proved undeveloped reserves			
As of December 31, 2013	4,839	–	4,839
As of December 31, 2014	7,549	359	7,908
As of December 31, 2015	5,217	173	5,390

	Turkey	Albania(1)	Total
		Gas (Mmcf)	
Total proved reserves			
December 31, 2012	12,463	–	12,463
Extensions and discoveries	2,652	–	2,652
Revisions of previous estimates	3,436	–	3,436
Sales volumes	(3,512)	–	(3,512)
December 31, 2013	15,039	–	15,039
Acquisitions	–	8,249	8,249
Extensions and discoveries	2,809	–	2,809
Revisions of previous estimates	1,668	–	1,668
Sales volumes	(3,262)	–	(3,262)
December 31, 2014	16,254	8,249	24,503
Extensions and discoveries	–	–	–
Revisions of previous estimates	2,084	(2,722)	(638)
Sales volumes	(2,491)	–	(2,491)
December 31, 2015	15,847	5,527	21,374
Proved developed reserves			
December 31, 2013:			
Proved developed producing	7,189	–	7,189
Proved developed non-producing	3,261	–	3,261
Total	10,450	–	10,450
December 31, 2014:			
Proved developed producing	5,572	–	5,572
Proved developed non-producing	3,979	–	3,979
Total	9,551	–	9,551
December 31, 2015:			
Proved developed producing	5,102	–	5,102
Proved developed non-producing	3,674	935	4,609
Total	8,776	935	9,711
Proved undeveloped reserves			
As of December 31, 2013	4,589	–	4,589
As of December 31, 2014	6,703	8,249	14,952
As of December 31, 2015	7,071	4,592	11,663

(1) As of December 31, 2015, we have classified our Albanian segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented.

Proved Reserves

At December 31, 2015, our estimated proved reserves were 18,636 Mboe, a decrease of 14,113 Mboe, or 43.1%, compared to 32,749 Mboe at December 31, 2014. This decrease was primarily attributable to the substantial decline in oil prices which caused developed and undeveloped reserves to become uneconomic at an earlier time and technical revisions on Albanian reserves based on actual performance following the 2015 work program.

At December 31, 2015, we recorded a decrease in proved reserves due to technical revisions of 12,303 Mbbl and 638 Mmcf (12,409 Mboe total). The revision in oil of 12,303 Mbbls was mostly attributable to pricing and economics due to the substantial decline in oil prices. As Brent oil price drops, wells become uneconomic at an earlier time thus reducing future reserves. Approximately 75% of these reductions were attributable to the Albania properties. There were no material revisions due to performance in Turkey. The revision in natural gas of 638 Mmcf was primarily attributable to a reduction in Delvina natural gas reserves of 2,722 Mmcf due to market constraints and a reduced realized price, which was partially offset by an increase in proved natural gas reserves for our Turkey assets of 2,084 Mmcf due to improved performance. The decrease in proved reserves also consisted of sales volumes of 2,066 Mboe in 2015, consisting of 1,651 Mbbls of oil and 2,491 Mmcf of natural gas. The estimated undiscounted capital costs associated with our proved reserves in Turkey is $167.9 million.

At December 31, 2015, we recorded an increase in proved reserves of 362 Mboe through extensions and discoveries. These increases were due to the discovery of productive pay in the Hazro formation in the Bahar oil field.

Proved Undeveloped Reserves

At December 31, 2015, our estimated proved undeveloped reserves were 7,334 Mboe, a decrease of 3,066 Mboe, or 29.5%, compared to 10,400 Mboe at December 31, 2014. Of this decrease in proved undeveloped reserves, 2,566 Mboe was due to lower pricing and capital constraints forcing a slower development of these locations. All of our proved undeveloped reserves as of December 31, 2015 will be developed within five years of the date the reserve was first disclosed as a proved undeveloped reserve. The estimated undiscounted capital costs associated with our proved undeveloped reserves in Turkey is $163.1 million of which $1.5 million is expected to be incurred in 2016. In addition, during 2015, we converted 500 Mboe from proved undeveloped to proved developed reserves and incurred $8.6 million of capital expenditures during 2015 to convert such reserves.

The proved undeveloped reserves assume development costs will be funded from future cash flows from operations and financing activities, which may not be sufficient or available at commercially economic terms and could impact the timing of these development activities.

Standardized measure of discounted future net cash flows

The Standardized Measure relating to estimated proved reserves as of December 31, 2015, 2014 and 2013 are shown in the table below. In our calculation of Standardized Measure, we have utilized statutory tax rates of 20% and 50% for Turkey and Albania, respectively.

	Turkey	Albania(1)	Total
		(in thousands)	
As of and for the year ended December 31, 2015			
Future cash inflows	$ 648,248	$ 205,829	$ 854,077
Future production costs	(140,091)	(116,617)	(256,708)
Future development costs	(167,914)	(26,474)	(194,388)
Future income tax expense	(28,900)	–	(28,900)
Future net cash flows	311,343	62,738	374,081
10% annual discount for estimated timing of cash flows	(112,116)	(35,851)	(147,967)
Standardized measure of discounted future net cash flows related to proved reserves	$ 199,227	$ 26,887	$ 226,114
As of and for the year ended December 31, 2014			
Future cash inflows	$ 1,504,369	$ 921,237	$ 2,425,606
Future production costs	(309,528)	(239,149)	(548,677)
Future development costs	(234,675)	(123,085)	(357,760)
Future income tax expense	(148,437)	(243,774)	(392,211)
Future net cash flows	811,729	315,229	1,126,958
10% annual discount for estimated timing of cash flows	(272,649)	(182,227)	(454,876)
Standardized measure of discounted future net cash flows related to proved reserves	$ 539,080	$ 133,002	$ 672,082
As of and for the year ended December 31, 2013			
Future cash inflows	$ 1,141,775	$ –	$ 1,141,775
Future production costs	(190,337)	–	(190,337)
Future development costs	(131,643)	–	(131,643)
Future income tax expense	(127,971)	–	(127,971)
Future net cash flows	691,824	–	691,824
10% annual discount for estimated timing of cash flows	(196,055)	–	(196,055)
Standardized measure of discounted future net cash flows related to proved reserves	$ 495,769	$ –	$ 495,769

(1) As of December 31, 2015, we have classified our Albanian segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented.

Changes in the standardized measure of discounted future net cash flows

The following are the principal sources of changes in the Standardized Measure applicable to proved oil and natural gas reserves for the years ended December 31, 2015, 2014 and 2013.

	Turkey	Albania(1)	Total
		(in thousands)	
For the year ended December 31, 2015			
Standardized measure, January 1,	$ 539,081	$ 133,001	$ 672,082
Net change in sales and transfer prices and in production (lifting) costs related to future production	(437,347)	(223,406)	(660,753)
Changes in future estimated development costs	44,691	52,914	97,605
Sales and transfers of oil and natural gas during the period	(69,843)	2,499	(67,344)
Net change due to extensions and discoveries	12,219	–	12,219
Net change due to revisions in quantity estimates	(73,697)	(96,727)	(170,424)
Previously estimated development costs incurred during the period	16,718	281	16,999
Accretion of discount	51,883	17,689	69,572
Other	8,769	(1,930)	6,839
Net change in income taxes	106,753	142,566	249,319
Standardized measure, December 31,	$ 199,227	$ 26,887	$ 226,114
For the year ended December 31, 2014			
Standardized measure, January 1,	$ 495,769	$ –	$ 495,769
Net change in sales and transfer prices and in production (lifting) costs related to future production	(75,912)	–	(75,912)
Changes in future estimated development costs	(151,238)	–	(151,238)
Sales and transfers of oil and natural gas during the period	(118,083)	–	(118,083)
Net change due to extensions and discoveries	245,643	–	245,643
Net change due to purchases of minerals in place	-	235,855	235,855
Net change due to revisions in quantity estimates	72,222	–	72,222
Previously estimated development costs incurred during the period	63,250	–	63,250
Accretion of discount	44,439	–	44,439
Other	(19,340)	–	(19,340)
Net change in income taxes	(17,669)	(102,854)	(120,523)
Standardized measure, December 31,	$ 539,081	$ 133,001	$ 672,082
For the year ended December 31, 2013			
Standardized measure, January 1,	$ 477,909	$ –	$ 477,909
Net change in sales and transfer prices and in production (lifting) costs related to future production	(7,868)	–	(7,868)
Changes in future estimated development costs	(73,753)	–	(73,753)
Sales and transfers of oil and natural gas during the period	(108,674)	–	(108,674)
Net change due to extensions and discoveries	112,814	–	112,814
Net change due to revisions in quantity estimates	7,678	–	7,678
Previously estimated development costs incurred during the period	47,252	–	47,252
Accretion of discount	56,376	–	56,376
Other	(12,070)	–	(12,070)
Net change in income taxes	(3,895)	–	(3,895)
Standardized measure, December 31,	$ 495,769	$ –	$ 495,769

(1) As of December 31, 2015, we have classified our Albanian segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented in our consolidated financial statements in this Annual Report on Form 10-K.

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, 2015, 2014 and 2013 are summarized as follows:

	Turkey	Albania	Bulgaria	Total
		(in thousands)		
For the year ended December 31, 2015				
Acquisitions of properties				
Proved	$ –	$ –	$ –	$ –
Unproved	–	–	–	–
Exploration	6,312	10,022	–	16,334
Development	15,654	285	41	15,980
Total costs incurred	$ 21,966	$ 10,307	$ 41	$ 32,314
For the year ended December 31, 2014				
Acquisitions of properties				
Proved	$ –	$ 99,927	$ –	$ 99,927
Unproved	–	16,140	–	16,140
Exploration	39,143	2,161	1,291	42,595
Development	63,250	110	44	63,404
Total costs incurred	$ 102,393	$ 118,338	$ 1,335	$ 222,066
For the year ended December 31, 2013				
Acquisitions of properties				
Proved	$ –	$ –	$ –	$ –
Unproved	6,750	–	–	6,750
Exploration	40,258	–	2,742	43,000
Development	47,252	–	–	47,252
Total costs incurred	$ 94,260	$ –	$ 2,742	$ 97,002

EXHIBIT INDEX

2.1	Stock Purchase Agreement, dated March 15, 2012, by and among TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd., Longe Energy Limited, TransAtlantic Petroleum (USA) Corp., TransAtlantic Petroleum Cyprus Limited, Viking International Limited, Viking Geophysical Services, Ltd., Viking Oilfield Services SRL and Dalea Partners, LP. (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 10, 2012).
2.2	Arrangement Agreement, dated as of September 2, 2014, between TransAtlantic Petroleum Ltd. and Stream Oil & Gas Ltd. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated September 2, 2014, filed with the SEC on September 8, 2014).
3.1	Certificate of Continuance of TransAtlantic Petroleum Ltd., dated October 1, 2009 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
3.2	Altered Memorandum of Continuance of TransAtlantic Petroleum Ltd., dated March 4, 2014 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated March 6, 2014, filed with the SEC on March 6, 2014).
3.3	Amended Bye-Laws of TransAtlantic Petroleum Ltd., dated March 4, 2014 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated March 6, 2014, filed with the SEC on March 6, 2014).
4.1	Amended and Restated Registration Rights Agreement, dated December 30, 2008, by and between TransAtlantic Petroleum Corp. and Riata Management, LLC (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated December 30, 2008, filed with the SEC on January 6, 2009).
4.2	Registration Rights Agreement, dated February 18, 2011, by and between TransAtlantic Petroleum Ltd. and Direct Petroleum Exploration, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated February 18, 2011, filed with the SEC on February 24, 2011).
4.3	Specimen Common Share certificate (incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K dated March 4, 2014, filed with the SEC on March 6, 2014).
4.4	Indenture, dated as of February 20, 2015, between TransAtlantic Petroleum Ltd. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated February 20, 2015, filed with the SEC on February 25, 2015).
4.5	Form of 13.0% Convertible Note due 2017 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K dated February 20, 2015, filed with the SEC on February 25, 2015).
10.1	Service Agreement, effective as of May 1, 2008, by and among TransAtlantic Petroleum Corp., Longfellow Energy, LP, Viking Drilling, LLC, Longe Energy Limited and Riata Management, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 6, 2008, filed with the SEC on February 12, 2009).
10.2	Amendment to Service Agreement, effective as of October 1, 2008, by and among TransAtlantic Petroleum Corp., Longfellow Energy, LP, Viking Drilling, LLC, Longe Energy Limited, MedOil Supply LLC and Riata Management, LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 6, 2008, filed with the SEC on February 12, 2009).
10.3	Domestic Crude Oil Purchase/Sale Agreement, dated as of January 26, 2009, by and between Türkiye Petrol Rafinerileri A.Ş. and TransAtlantic Exploration Mediterranean International Pty. Ltd. (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
10.4†	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).
10.5†	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).
10.6	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).
10.7†	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).

10.8	Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking International Limited (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
10.9	Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
10.10	Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Geophysical Services, Ltd. (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
10.11	Transition Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum, Ltd. and Viking Services Management, Ltd. (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).
10.12	Office Lease, dated April 5, 2013, by and between TransAtlantic Petroleum (USA) Corp. and Longfellow Energy, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated May 8, 2013, filed with the SEC on May 14, 2013).
10.13	Equipment Yard Services Agreement, by and between TransAtlantic Exploration Mediterranean International Pty Ltd, Thrace Basin Natural Gas (Turkiye) Corporation and Viking International Limited, dated as of April 1, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated March 26, 2014, filed with the SEC on March 28, 2014).
10.14	Credit Agreement, dated as of May 6, 2014, 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., 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 BNP Paribas (Suisse) SA as coordinating mandated lead arranger, sole bookrunner, letter of credit issuer, administrative agent, collateral agent and technical agent and International Finance Corporation, as mandated lead arranger (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 8, 2014).
10.15†	Summary of annual restricted stock award arrangement with Mr. Wil F. Saqueton (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 6, 2014).
10.16	Facility Agreement, dated December 15, 2011, by and among Stream Oil & Gas Ltd., Stream Oil & Gas Ltd. (BC), and Raiffeisen Bank Sh.A (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K, filed with the SEC on March 16, 2016).
10.17	Amended and Restated Facility Agreement, dated September 17, 2014, by and among Stream Oil & Gas Ltd., Stream Oil & Gas Ltd. (BC), and Raiffeisen Bank Sh.A (incorporated by reference to Exhibit 10.23 to the Company's Annual Report on Form 10-K, filed with the SEC on March 16, 2016).
10.18	Amendment and Restatement Agreement, dated September 17, 2014, by and among Stream Oil & Gas Ltd., Stream Oil & Gas Ltd. (BC), and Raiffeisen Bank Sh.A (incorporated by reference to Exhibit 10.24 to the Company's Annual Report on Form 10-K, filed with the SEC on March 16, 2016).
10.19	Promissory Note dated August 21, 2015 between TransAtlantic Petroleum (USA) Corp. and Gary West CRT 2 LLC (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 5, 2015).
10.20	Promissory Note dated August 21, 2015 between TransAtlantic Petroleum (USA) Corp. and Mary West CRT 2 LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 5, 2015).
10.21	Convertible Promissory Note, by and between TransAtlantic Petroleum Ltd. and ANBE Holdings, LP, dated December 30, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the SEC on January 6, 2016).
10.22*	Amended Promissory Note Term Sheet dated March 30, 2016, by and between TransAtlantic Petroleum Ltd. and Dalea Partners, LP.
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 February 28, 2016.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

† Management contract or compensatory plan arrangement.
* Filed herewith.
** Furnished herewith.