VAALCO ENERGY INC /DE/
Form 10-K
March 16, 2015

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, 2014

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: 1-32167

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Delaware	76-0274813
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

9800 Richmond Avenue

Suite 700

Houston, Texas 77042

(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): (713) 623-0801

Securities registered under Section 12(b) of the Exchange Act:

Title of each class	Name of exchange on which registered
Common Stock, $.10 par value	New York Stock Exchange

Securities registered under Section 12(g) of the Exchange 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 15d 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 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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ 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 the voting and non-voting common equity of the registrant held by non-affiliates, as of June 30, 2014 was $411,807,121 based on a closing price of $7.23 on June 30, 2014.

As of February 28, 2015, there were outstanding 57,880,481 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Definitive proxy statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which is incorporated into Part III of this Form 10-K.

VAALCO ENERGY, INC.

TABLE OF CONTENTS

Glossary of Oil and Gas Terms

Terms used to describe quantities of oil and natural gas

Bbl — One stock tank barrel, or 42 US gallons liquid volume, of crude oil or other liquid hydrocarbons.
BOE — One barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and gas business and represents the approximate energy equivalency of six Mcf of natural gas to one Bbl of oil or liquids, and does not represent the sales price equivalency of natural gas to oil or liquids. Currently, the sales price of Bbl of oil or natural gas liquids is significantly higher than the sales price of six Mcf of natural gas.
BOPD — One barrel of oil per day.
MBbl — One thousand Bbls.
Mcf — One thousand cubic feet of natural gas.
MMcf — One million cubic feet of natural gas.

Terms used to describe the Company's interests in wells and acreage

Gross oil and gas wells or acres — The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
Net oil and gas wells or acres — Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.

Terms used to assign a present value to the Company's reserves

Standard measure of proved reserves — The present value, discounted at 10%, of the future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the prices used in the report, unless it had a contract to sell the production for a different price. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes using rates in effect on the date of the report are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.

Terms used to classify the Company's reserve quantities

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Standardized measure. Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission, using prices and costs in effect as of the date of estimation, without giving effect to non–property related expenses such as certain general and administrative expenses, debt service and future federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productibility at greater distances.

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

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

Unproved properties. Properties with no proved reserves.

Terms which describe the productive life of a property or group of properties

Reserve life. A measure of the productive life of oil and gas property or a group of oil and gas properties, expressed in years. Reserve life for the years ended December 31, 2014, 2013 or 2012 equal the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

Terms used to describe the legal ownership of the Company's oil and gas properties

Royalty interest. A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the minerals on the land.

Working interest. A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

Seismic data. Oil and gas companies use seismic data as their principal source of information to locate oil and gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

2-D seismic data. 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

3-D seismic data. 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

PART I

Item 1. Business
BACKGROUND

VAALCO Energy, Inc., a Delaware corporation incorporated in 1985, is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. VAALCO owns producing properties and conducts exploration activities as an operator in Gabon, West Africa, conducts exploration activities as an operator in Angola, West Africa, and participates in exploration and development activities as a non-operator in Equatorial Guinea, West Africa. VAALCO is the operator of unconventional resource properties in the United States in North Texas and a leasehold in Montana. The Company also owns minor interests in conventional production activities as a non-operator in the United States. As used in this report, the terms “Company”, “we”, “us”, “our”, and “VAALCO” mean VAALCO Energy, Inc. and its subsidiaries, unless the context otherwise requires. The Company’s corporate headquarters are located at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042 where the telephone number is (713) 623-0801.

VAALCO’s international subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., VAALCO International, Inc., VAALCO Energy (EG), Inc. and VAALCO Energy Mauritius (EG) Limited. VAALCO Energy (USA), Inc. holds interests in properties located in the United States.

STRATEGY

International

The Company’s international strategy is to pursue selective opportunities with a focus on West Africa that are characterized by reasonable entry costs, favorable economic terms, high reserve potential relative to capital expenditures and the availability of existing technical data. The Company believes that it has strong management and technical expertise with proven abilities in identifying international opportunities and establishing favorable operating relationships with host governments and local partners familiar with the local practices and infrastructure. The Company owns producing properties and conducts operating activities as an operator under an offshore license in Gabon, a license onshore Gabon (subject to approval of a new production sharing agreement which will include an extension of the exploration license), an exploration license in Angola, and as non-operator of an exploration/development license in Equatorial Guinea.

In addition, the Company’s production strategy is to maximize the value of the reserves discovered in Gabon through development of the offshore Etame Marin block (comprised of the Etame, Avouma/South Tchibala, and Ebouri producing fields, and the Southeast Etame/North Tchibala field currently being developed), and the onshore Mutamba Iroru block where the N’Gongui field is expected to be developed following the approval of a new production sharing contract with the Republic of Gabon.

Domestic

The Company’s domestic strategy has been to selectively acquire unconventional resource based properties. The Company owns a lease with two producing wells in the Granite Wash formation in Texas, and deep rights on a lease in Montana. Due to the surplus of domestically produced light, sweet crude oil in North America, and the associated current low price environment, the Company does not expect to focus on further development of domestic owned properties in its short-term business plans.

RECENT DEVELOPMENTS

Offshore Gabon

The Company’s primary source of revenue is from the Etame Production Sharing Contract related to the Etame Marin block located offshore the Republic of Gabon. VAALCO operates the Etame Marin block on behalf of a consortium of companies. At December 31, 2014, the Company owns a 28.1% interest in the development areas in and surrounding the Etame, Avouma/South Tchibala, and Ebouri fields, each of which is located on the Etame Marin block. The development areas were subject to a 7.5% back-in by the Government of Gabon, which occurred for these fields after their successful development. The Southeast Etame/North Tchibala field, each of which is also located on the Etame Marine block are in the process of being developed and will also be subject to a 7.5% back-in by the Government of Gabon. The Government of Gabon has since assigned the back-in interest to a third party.

The Company produces from the Etame, Avouma/South Tchibala and Ebouri fields on the block. During 2014, these fields produced approximately 5.8 million Bbls (1.4 million Bbls net to the Company). The Company’s share of barrels produced reflects an allocation of cost oil and profit oil, after reduction for royalty (13%).

In July 2012, the Company discovered the presence of hydrogen sulfide (“H_2S”) from two of the three producing wells in the Ebouri field. The wells were shut-in for safety and marketability reasons resulting in a decrease of approximately 2,000 BOPD or approximately 10% of the gross daily production from the Etame Marin block at that time. In addition, H_2S was first detected in January 2014 and later confirmed in July 2014 in the Etame 5-H well in the Etame field, and this well has also been shut-in. Analysis and options for re-establishing production from the impacted areas continued through the fourth quarter of 2014. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including a processing facility capable of removing H_2S, recompletion of the temporarily abandoned wells, and potentially, additional new wells. Considering the substantial recent fall in oil prices, the Company and its partners are focusing on more cost efficient options for a processing facility (e.g. chemical removal options, construction of a smaller facility on existing structures, or the use of surplus equipment and used structures). There can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will cover all affected areas of the Ebouri and Etame fields. It is expected that the timing of the project startup will be known as early as the fourth quarter of 2015 with a goal of re-establishing production from the area impacted by H_2S as soon as practical. Should the Company and its partners evaluation result in no economic alternative, a decrease of as much as 2.4 million barrels of proved undeveloped reserves could result.

The Company and its partners approved the construction of two additional production platforms in late 2012 as part of future development plans for the Etame Marin block. The construction of the two new platforms began in the first quarter of 2013 and were installed in the third quarter of 2014. One platform was installed in the Etame field and the second platform was installed between the Southeast Etame/North Tchibala field. The Company contracted a drilling rig to commence a multi-well development drilling program, which moved onto location and began drilling the first well in November 2014 from the Etame platform, in the Etame field. The Company drilled a successful exploration well in the Southeast Etame area in 2010 which is expected to be developed from the second platform in 2015. The total cost to build and install the two platforms was $351.0 million ($106.5 million net to the Company). The cost of the wells is not included in the platform costs.

The sixth extension of the exploration acreage on this block expired at the end of July 2014. The Company fully met all of the obligations under the terms of the sixth extension period. In the second quarter of 2014, and prior to the deadline, the Company and its partners submitted a proposal for a seventh exploration license. The Government of Gabon responded in the first quarter of 2015 that a seventh exploration license would require a separate production sharing contract (“PSC”) and this requirement is being evaluated by the Company and its partners.

Due to the uncertainty of obtaining the exploration license, the balance of undeveloped leasehold costs of $1.6 million was recorded as exploration expense in the year ended December 31, 2014.

Late in 2012, a drilling and workover campaign began with the arrival of a drilling rig to conduct a six well program that was ultimately increased to an eight well program extending into 2014. The early-2014 program included the drilling of an exploration well that did not discover commercial quantities of hydrocarbons. Accordingly, the Company expensed $1.9 million of incurred dry hole costs in the fourth quarter of 2013 for this well, with the remainder of $11.7 million of dry hole costs expensed in the first quarter of 2014. The Company performed a workover to replace the electrical submersible pumps in a well in the Avouma field in the first quarter of 2014 and in May 2014 brought on production a development well drilled in the South Tchibala field to replace a well with damaged casing.

Following the installation of the two additional platforms in the third quarter of 2014, the Company and its partners began a development well drilling campaign beginning in October 2014 from the Etame platform. The first well drilled, the Etame 8-H well, was completed in December 2014 and was shut-in as the well was determined to be producing H_2S during the initial testing process. The Company is planning to conduct an extended well test of the Etame 8-H well, to confirm and quantify the presence of H_2S which was detected during the initial 17 hour flow test. The well test is expected to occur in the first half of 2015. In December 2014, the Company spudded the Etame 10-H well which was drilled to the 1-V fault block, and the well was brought on production in the first quarter of 2015. The Etame 10-H well confirmed the presence of an undrained lower lobe of the Gamba reservoir in this fault block with no H_2S present. Additional development wells are expected to be drilled in 2015 from the two platforms.

As part of securing the first of two five-year extensions in 2011 to the Etame field production license to which the Company is entitled from the government of Gabon, the Company agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin Block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over the remaining life of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The initial funding took place in October 2014 for calendar years 2012 and 2013 totaling $8.4 million ($2.3 million net to the Company). The funding for calendar year 2014 was paid in the first quarter of 2015 in the amount of $4.2 million ($1.2 million net to the Company). As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company's balance sheet. The cash funding is reflected under other long term assets as "Abandonment Funding".

In the fourth quarter of 2014, the Company recorded an impairment loss of $98.3 million to write down its investment in certain fields comprising the Etame Marin Block, offshore Gabon to its fair value. An impairment of $38.5 million was recorded in the Etame field, $5.9 million in the Ebouri field and $53.9 million in the Southeast Etame/North Tchibala field. The impairment is a result of the recent decline in the forecasted oil prices used in the impairment testing and calculation.

Onshore Gabon

The Company executed a farm-out agreement in August 2010 with Total Gabon on the Mutamba Iroru block located onshore near the coast in central Gabon. The Mutamba Iroru block contains an exploration area of approximately 270,000 acres. The Company has a 50% working interest on the block (41% net working interest assuming the Republic of Gabon exercises its back-in rights).

Under the terms of the agreement, the Company and Total Gabon committed to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. The seismic reprocessing work was completed in 2012. The exploration well was drilled in 2012 resulting in a discovery.

A revised production sharing contract ("PSC") including exploration rights is in the approval process. The term sheet, which specifies financial and other obligations to be included in the PSC, was agreed to and signed by the Company, its joint venture partner, and the Government of Gabon on July 31, 2014. The form of the PSC has been completed and presented to the Company and its joint venture partner for execution. The joint venture partner has withheld its approval of the new PSC pending resolution of certain legal aspects of the new agreement with the Government of Gabon. In March 2015, the joint venture partner indicated to the Company that the legal aspects have not yet been resolved to their satisfaction. The Company can provide no assurance as to the joint venture partner approving the PSC. The Company remains committed to this block and further meetings of the parties are expected to occur in the first half of 2015.

After the PSC is approved, an application for a development area will be made by the Company. After issuance of a development area, the next step is the submittal of the plan of development. The Company can provide no assurances as to either the approval of the PSC by the Government of Gabon, or the subsequent approval of a development area by the Government of Gabon.

Development of the onshore block is expected to capitalize on synergies such as experienced personnel from our operating base office space, warehouse and open yard space in Port Gentil, Gabon.

Offshore Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%, and its paying interest is 50% including the government's carried working interest during the exploration phase.

By a governmental decree dated December 1, 2010, the government-assigned working interest partner was removed from the production sharing contract for cause, and a one year time extension was granted for drilling the two exploration commitment wells while the government decided on the disposition of the available interest. Additional extensions were subsequently granted by the Angolan government until November 30, 2014 to drill the two exploration commitment wells.

In the fourth quarter of 2013, the Company received a written confirmation from The Ministry of Petroleum of Angola that the available 40% working interest in Block 5, offshore Angola, has been assigned to Sonangol E.P., the National Concessionaire. The Ministry of Petroleum also confirmed that Sonangol E.P. would assign the aforementioned participating interest to its exploration and production affiliate, Sonangol P&P. The assignment was made effective on January 1, 2014.

In April 2014, the Company received a letter and contractual amendment proposal from Sonangol E.P., the national oil company in Angola related to the extension of the two well drilling commitment. Due to the uncertainty that the primary term of the exploration license would be extended by the Republic of Angola in accordance with the contractual amendment proposal before the November 30, 2014 expiration date, in October 2014, the Company entered into the Subsequent Exploration Phase (“SEP”), together with its working interest partner, Sonangol P&P. The SEP option was provided for in the Production Sharing Agreement signed in 2006 with the Republic of Angola. The SEP extends the exploration period for an additional three year period such that the new expiry date for exploration activities is November 30, 2017. Entering the SEP requires the Company and its partner to acquire 3D seismic covering six hundred square kilometers and to drill two additional exploration wells. The Company has already satisfied the seismic obligation of the SEP with the purchase of 3D seismic in the outboard segment of the block in late 2013, which is currently being processed and will continue to be processed into 2015.

By entering into the SEP, the Company is required to drill a total of four exploration wells during the exploration extension period. The four well obligations include the two well commitments under the primary exploration period that carries over to the SEP period. A $10.0 million dollar assessment ($5.0 million dollars net to VAALCO) applies to each of the four commitment exploration wells, if any, that remain undrilled at the end of the exploration period in November 2017. Restricted cash of $10.0 million for the two new commitment wells was recorded in the fourth quarter of 2014. At December 31, 2014 the Company had $20.0 million in restricted cash related to the offshore Angola exploration agreement.

A drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well began drilling in the first quarter of 2015. Drilling this well satisfies one of the four exploration well obligations and will release $5.0 million of the $20.0 million recorded as restricted cash at December 31, 2014 by the Company.

Offshore Equatorial Guinea

In July 2012, the Company signed a definitive agreement with Petronas Carigali Overseas SDN BHD for the purchase of a 31% working interest in Block P, located offshore Equatorial Guinea for 57,000 acres at a cost of $10.0 million. The acquisition was completed on November 1, 2012. GEPetrol, the national oil company of Equatorial Guinea, is the operator of the block. During 2014, the Company and GEPetrol continued to work on a joint operatorship model whereby the Company would have a significant role in operator activities on the block. Additionally, the Company has been working with the Ministry of Mines, Industry and Energy regarding timing and budgeting for development and exploration activities.

AVAILABLE INFORMATION

The Company files annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). You may read and copy any document the Company files at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. The Company's SEC filings are also available to the public at the SEC's website at www.sec.gov.

You may also obtain copies of the Company's annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from the Company's website at www.vaalco.com. No information from the SEC's or the Company's website is incorporated by reference herein. The Company has placed on its website copies of its Audit Committee Charter, Code of Business Conduct and Ethics, and Code of Ethics for the Chief Executive Officer and Chief Financial Officer. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, VAALCO Energy, Inc., 9800 Richmond Avenue, Suite 700, Houston, Texas 77042.

CUSTOMERS

Substantially all of the Company's oil and gas is sold at posted or indexed prices under short-term contracts, as is customary in the industry. In Gabon, starting in the second quarter of 2014, the Company switched to an agency model to sell its crude oil. The Company contracted with a third party in order to sell, based on a fixed per barrel fee, on the spot market ("agency model"). Prior to the second quarter in 2014, the Company sold oil under contracts with Mercuria Trading NV ("Mercuria") beginning with the calendar year 2011. For the first quarter of 2015, the Company will also sell its oil under the agency model on the spot market.

Domestic operated production in Texas is sold via two contracts, one for oil and one for gas and natural gas liquids. The Company has access to several alternative buyers for oil, gas, and natural gas liquids domestically.

EMPLOYEES

As of December 31, 2014, the Company had 113 full-time employees and consultant contractors, 60 of whom were located in Gabon, 7 of whom were located in Angola and 1 employee located in Equatorial Guinea. The Company is not subject to any collective bargaining agreements, although most of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. The Company believes its relations with its employees are satisfactory.

COMPETITION

The oil and gas industry is highly competitive. Competition is particularly intense from other independent operators and from major oil and natural gas companies with respect to acquisitions of desirable oil and gas properties and contracting for drilling equipment. There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of oil and gas is affected by a number of factors beyond the control of the Company, including but not limited to shortages of drilling rigs, pipe and personnel, which may delay drilling, increase prices and have other adverse effects which cannot be accurately predicted.

The Company's competition for acquisitions, exploration, development and production includes the major oil and gas companies in addition to numerous independent oil companies, individual proprietors, investors and others. Many of these competitors possess financial, technical and personnel resources substantially in excess of those available to the Company, giving those competitors an enhanced ability to evaluate and acquire desirable leases properties or prospects. The ability of the Company to generate reserves in the future will depend on its ability to select and acquire suitable producing properties and prospects for future drilling and exploration.

INSURANCE

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. The Company currently has insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to its oil and gas properties, operational control of offshore wells, aviation, auto liability, marine liability, worker's compensation and employer's liability, among other things. At the depths and in the areas in which the Company operates, and in light of the vertical and horizontal drilling that it undertakes, the Company typically does not encounter high pressures or high temperature drilling conditions.

Currently, the Company has Operator's Extra Expense insurance coverage up to $100.0 million per occurrence. This includes coverage for redrill and restoration of wells, as well as coverage for resultant environmental damage, including voluntary clean-up. The Company also carries Physical Damage coverage on offshore assets that is subject to full replacement cost limits. Both of these coverages, Operator's Extra Expense and Physical Damage, are subject to certain customary exclusions and limitations and to deductibles (generally ranging from $100,000 to $1,000,000 per occurrence) that must be met prior to recovery. In addition, the Company carries General Liability and Excess Liability Insurance, subject to customary exclusions and limitations, with limits of $75.0 million. This program includes coverage for bodily injury and property damage to third parties, including sudden and accidental pollution liability coverage.

The Company requires all of its third-party contractors to sign master service agreements in which they agree to indemnify the Company for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by the Company's employees and other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations for the Company sign the master service agreements containing the indemnification provisions noted above. The Company does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, the Company believes its general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. The Company does not have ongoing hydraulic fracturing operations at December 31, 2014 nor plans for any such operations in the near future.

The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that the Company will be able to maintain insurance in the future at rates that we consider reasonable and it may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

ENVIRONMENTAL REGULATIONS

General

The Company’s activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control in the United States and Gabon and will be subject to the laws and regulations of Angola and Equatorial Guinea when exploration drilling begins in those countries. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the Company’s capital expenditures, earnings or competitive position with respect to its existing assets and operations. The Company cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from the Company’s operations could have on its activities. In part because they are developing countries, it is unclear how quickly and to what extent Gabon, Angola or Equatorial Guinea will increase their regulation of environmental issues in the future; any significant increase in the regulation or enforcement of environmental issues by Gabon, Angola or Equatorial Guinea could have a material effect on the Company. Developing countries, in certain instances, have patterned environmental laws after those in the United States which are discussed below. However, the extent to which any environmental laws are enforced in developing countries varies significantly.

In the United States, environmental laws and regulations may require the acquisition of permits before drilling commences, the installation of pollution control equipment for our operations, special handling or disposal of materials used in our operations, or remedial measures to mitigate pollution from our operations or on the properties on which we operate. These laws and regulations may also restrict the types of substances used in our drilling operations which can be used or released into the environment or limit or prohibit drilling activities on certain lands such as wetlands or sensitive protected areas or restrict the rate of production below the rate that would otherwise be possible..

As a general matter, the oil and gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. The Environmental Protection Agency ("EPA") has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for 2014-2016. The trend has been the enactment of new or more stringent requirements on the oil and gas industry. These changes result in increased operating costs, and additional changes could results in further increases in our costs for environmental compliance.

Environmental Regulations in the United States

Superfund

The Company currently owns or leases, and in the past has owned or leased, properties that have been used for the exploration and production of oil and gas for many years. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by the Company or on or under locations where such wastes have been taken for disposal. In addition, some of these properties are or have been operated by third parties. The Company has no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. The Company could, in the future, be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of Hazardous Substances found at a facility. CERCLA also authorizes the (EPA) and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action.

Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate substances that may fall within CERCLA's definition of Hazardous Substance and may have disposed of these substances at disposal sites owned and operated by others. The Company may also be the owner or operator of sites on which Hazardous Substances have been released. To its knowledge, neither the Company nor its predecessors have been designated as a PRP by the EPA under CERCLA; the Company also does not know of any prior owners or operators of its properties that are named as PRPs related to their ownership or operation of such properties. States such as Texas have comparable statutes which may cover substances (including petroleum) in addition to those covered under CERCLA. In the event contamination is discovered at a site on which the Company is or has been an owner or operator or to which the Company sent regulated substances, the Company could be liable for costs of investigation and remediation and natural resources damages.

Solid and Hazardous Waste Handling

The Company generates wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under RCRA and state analogs ("Hazardous Wastes"). Furthermore, although most oil and gas wastes generally are exempt from regulation as hazardous waste, not all current comparable state statutes may provide this exemption, and certain wastes generated by the Company may be subject to RCRA or comparable state statutes. It is possible that certain wastes generated by the Company's oil and gas operations that are currently exempt may in the future be designated as

Hazardous Wastes under RCRA or other applicable statutes and, therefore, may be subject to more rigorous and costly disposal requirements.

Clean Water Act

The Clean Water Act (“CWA”) and analogous state laws impose restrictions and strict controls regarding the discharge (including spills and leaks) of pollutants, including produced waters and other oil and natural gas wastes, into state waters and waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Generally, permits must be obtained to discharge pollutants. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and hazardous substances and of other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or other pollutants. The CWA also prohibits the discharge of fill materials to regulated waters, including wetlands, without a permit. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other pollutants, into state waters. In addition, the EPA has promulgated regulations that may require the Company to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, the Company may be liable for penalties and cleanup and response costs.

Oil Pollution Act

The Oil Pollution Act of 1990 (“OPA”), which amends and augments oil spill provisions of the CWA, imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 Bbls to demonstrate financial responsibility in amounts ranging from $10.0 million in specified state waters and $35.0 million in federal outer continental shelf (“OCS”) waters, with higher amounts, up to $150.0 million based upon worst case oil-spill discharge volume calculations. In light of recent events, it is possible that these requirements may become more stringent. The Company believes that currently it has established adequate proof of financial responsibility for its offshore facilities.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand (or other proppant) and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not as extensively at the federal level. For example, the federal Safe Drinking Water Act (“SDWA”) protects underground sources of drinking water through the EPA’s underground injection control (“UIC”) program, which regulates the subsurface emplacement of fluid. The definition of “underground injection” in the SDWA expressly excludes the “underground injection of fluids or propping agents (other than diesel fuel) pursuant to hydraulic fracturing operations.” Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal and state levels that could result in regulation of hydraulic fracturing becoming more stringent and costly.

In February 2014, the EPA issued guidance regarding federal regulatory authority under the SDWA over hydraulic fracturing using diesel fuel, specifying that owners or operators of wells who inject diesel fuels for hydraulic fracturing related to oil and gas operations must obtain a permit under the Class II well category under the EPA's UIC program regulations before injection begins. This guidance also identified fluids associated with five Chemical Abstracts Services (CAS) registry numbers as the most appropriate interpretation of the statutory term "diesel fuels" to use for permitting hydraulic fracturing that uses diesel fuels under the EPA's UIC program. This guidance also clarified that diesel fuels used as a component of drilling muds or pipe joint compounds used in the well construction process or in motorized equipment at the surface are not subject to UIC Class II permitting requirements because such uses of diesel fuels are considered to be part of the well construction process and not diesel fuels injected for purposes of hydraulic fracturing.

The EPA also commenced a study of the potential environmental impacts of hydraulic fracturing activities and released a progress report in December 2012, which resulted in the EPA's Subpart OOOO regulations (see discussion below) signed by the EPA Administrator on December 19, 2014.

In addition, a committee of the U.S. House of Representatives conducted an investigation of hydraulic fracturing practices. Moreover, in past sessions legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing by eliminating the current exemption in the Safe Drinking Water Act, and, further, to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that restrict hydraulic fracturing in certain circumstances or that require disclosure of the chemicals in the fracturing fluids. Additionally some states, localities and river basin conservancy districts have exercised or considered exercising their regulatory powers to limit, and in some cases place a moratorium on hydraulic fracturing.

The Bureau of Land Management ("BLM") has regulated hydraulic fracturing activities on federal lands since 1983, but the BLM's existing regulations were not written to address modern hydraulic fracturing activities. The BLM has proposed revisions to its hydraulic fracturing regulations, which could require disclosure of hydraulic fracturing chemicals and the volume of water used. Such proposed regulations are still pending before the BLM.

Further, in response to a petition filed in January 2012 under section 21 of the Toxic Substances Control Act ("TSCA"), the EPA issued an Advance Notice of Proposed Rulemaking, RIN 2070-AJ93 ("ANPR"), which was published in the Federal Register on May 19, 2014. The EPA indicated that the purpose of this ANPR is soliciting public comment on the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and the mechanism for obtaining this information, minimizing reporting burdens and avoiding duplication of state and other federal agency information collections, and soliciting comments on incentives and recognition programs that "could be used to support the development and use of safer chemicals in hydraulic fracturing". The public comment period for this ANPR was extended for an additional month and ended on September 18, 2014. The next phase of this regulatory rulemaking process is still pending at the EPA.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where the Company conducts business, the Company could incur substantial compliance costs and such requirements could adversely delay or restrict its ability to conduct fracturing activities on its assets.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA, this process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases (“GHGs”) may be adopted in the future and could cause us to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants. In addition, both houses of the United States Congress have considered legislation to reduce emissions of greenhouse gases without any ultimate resolution and many states have taken or considered legal measures to reduce GHG emissions, including, in a few locations, the consideration of a cap and trade program. Most cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. Depending on the regulatory reach of the EPA’s rules or new Clean Air Act (“CAA”) legislation or implementing regulations restricting the emission of GHGs or state programs, the Company could incur significant costs to control its emissions and comply with regulatory requirements. In addition, the EPA adopted a mandatory GHG emissions reporting program which imposes reporting and monitoring requirements on various industries including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. The Company will incur costs to monitor, keep records of, and report emissions of GHGs. We do not believe that our compliance with applicable monitoring, recordkeeping and reporting requirements under the reporting rule will have a material adverse effect on our results of operations or financial position.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how federal and state regulation of GHGs will unfold and how it may impact our industry. Moreover, the federal, regional, state and local regulatory initiatives could adversely affect the marketability of the oil and natural gas that the Company produces. The impact of such future programs cannot be predicted, but the Company does not expect its operations to be affected any differently than other similarly situated domestic competitors.

The EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. The measures include the development of New Source Performance Standards (“NSPS”) regulations in 2016 for reducing methane from new and modified oil and gas production sources, and natural gas processing and transmission sources.

Air Emissions

The Company’s operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. At the Federal level, the Clean Air Act (“CAA”) is the primary statute governing air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants might require installation of additional controls. Administrative enforcement actions for failure to comply with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require the Company to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA issued final rules to subject oil and gas operations to regulation under the NSPS and National Emission Standards for Hazardous Air Pollutants (“NESHAPS”) programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. On December 19, 2014, the EPA Administrator signed and submitted for publication in the Federal Register (77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014) the EPA’s finalized amendments to the NSPS with respect to emissions from the oil and natural gas sector, entitled

"Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution" (40 CFR Part 60, Subpart OOOO). Section 60.5375(a) of Subpart OOOO of the EPA rules includes NSPS standards for completions of hydraulically fractured natural gas wells. These standards are applicable to new hydraulically fractured wells and also existing wells that are refractured.

For each well completion operation with hydraulic fracturing begun prior to January 1, 2015, these standards require owners/operators to comply with Section 60.5375(a)(3) and (4) and reduce volatile organic compound ("VOC") emissions from natural gas not sent to the gathering line during well completion by flaring using a completion combustion device, with the option to capture the gas emissions using reduced emission completions ("REC" aka "green completions"). For each well completion with hydraulic fracturing begun on or after January 1, 2015, operators must comply with Section 60.5375(a)(1) and (2) and capture the gas and make it available for use or sale, which can be done through the use of green completions. Section 60.5375(a)(1) distinguishes between the "initial flowback stage" of a well completion (specifying that gas present in the initial flowback stage is not subject to control under Section 60.5375(a)(1)) and the "separation flowback stage" of a well completion. Section 60.5375(a)(1)(ii) specifies that gas present in the separation flowback stage must be recovered from the separator and routed into a gas flow line or collection system, reinjected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve. If it is infeasible to route the recovered gas as specified above, then it is to be flared using a completion combustion device in accordance with Section 60.5375(a)(3).

Further, the finalized Subpart OOOO regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment.

These rules may require changes to our operations, including the installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

OSHA and Other Regulations

To the extent not preempted by other applicable laws, the Company is subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes, where applicable. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes, where applicable, require the Company to organize, maintain and/or disclose information about hazardous materials used or produced in its operations.

FORWARD-LOOKING STATEMENTS

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created by those laws. The Company has based these forward-looking statements on its current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of the Company’s operations. All statements, other than statements of historical facts, included in this report that address activities, events or developments that the Company expects or anticipates may occur in the future, including without limitation, statements regarding the Company’s financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures, plans and objectives of the Company’s management for future operations are forward-looking statements. When the Company uses words such as “anticipate,” “believe,” “estimate,” “expect,” “intend,” “forecast,” “outlook,” “aim,” “will,” “could,” “should,” “may,” “likely,” “plan,” “probably” or similar expr Company is making forward-looking statements. Many risks and uncertainties that could affect the Company’s future results and could cause results to differ materially from those expressed in the Company’s forward-looking statements include, but are not limited to:

- the volatility of recent severe downturn in of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in measuring, transporting and delivering oil to commercial markets;
- discovery, acquisition, development and replacement of oil and gas reserves;
- timing and amount of future production of oil and gas;
- potential reductions in the borrowing base and our ability to meet the financial covenants of our credit facility;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- our ability to effectively integrate companies and properties that we acquire;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;

changes in customer demand and producers' supply;
future capital requirements and the Company's ability to attract capital;
currency exchange rates;
actions by the governments and events occurring in the countries in which we operate;
actions by our venture partners;

- compliance with, or the effect of changes in, governmental regulations regarding the Company's exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit;
- actions of operators of the Company's oil and gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could cause the Company's results or performance to differ materially from those the Company expresses in its forward-looking statements. Although the Company believes that the assumptions underlying its forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements which are included in this report, the Company's inclusion of this information is not a representation by the Company or any other person that the Company's objectives and plans will be achieved. When you consider the Company's forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this report.

The Company's forward-looking statements speak only as of the date made and the Company will not update these forward-looking statements unless the securities laws require the Company to do so. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. In light of these risks, uncertainties and assumptions, any forward-looking events discussed in this report may not occur.

Item 1A. Risk Factors
You should carefully consider the following risk factors in addition to the other information included in this report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us.

Almost all of the value of our production and reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.

The Etame field consisting of three producing wells, the Avouma/South Tchibala fields consisting of three wells, and the Ebouri field with one producing well constituted approximately 97% of our total production for the year ended December 31, 2014. In addition, at December 31, 2014, 97% of our total net proved reserves were attributable to these fields. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations, financial condition, and cash flows could be materially adversely affected.

Additionally, we discovered the presence of H_2S from two of our producing wells in the Ebouri field in 2012 and one in the Etame field in 2014. At year end 2014 we intended to, and we still may, build a processing facility capable of removing H_2S from production in order to re-establish and maximize production from the impacted areas. However, subsequent to 2014 year end, as a result of the substantial recent fall in oil prices, we are considering more cost efficient options, and there can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will re-establish production to all affected wells in the Ebouri and Etame fields. A determination to not build the processing facility in order to re-establish production or to build a more cost effective facility that does not re-establish all production from affected wells could force us to reclassify certain of our proved reserves in these fields as unproved reserves.

Oil and natural gas prices are highly volatile, and continued depressed prices will negatively affect our financial results.

Our revenues, cash flow, profitability, oil and natural gas reserves value and future rate of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil and natural gas prices. Historically, world-wide oil and natural gas prices and markets have been volatile, and may continue to be volatile in the future. In particular, the prices of oil and natural gas were highly volatile in 2014 and declined dramatically in the second half of the year. For example, during 2014, based on NYMEX pricing, the price for a barrel (bbl) of oil ranged from a high of $107.26 to a low of $53.27 and the price for an Mmbtu of natural gas ranged from a high of $8.15 to a low of $2.74.

Continued depressed oil and natural gas prices or any other unfavorable market conditions could have a material adverse effect on our financial condition and on the carrying value of our proved reserves. The average price at which we sold in 2014 was $93.66 per barrel compared to $108.35 per barrel in 2013, and $111.06 per barrel in 2012. Because the oil price we are required to use by Security and Exchange Commission ("SEC") to estimate our future net cash flows is the average price over the 12 months prior to the date of determination of future net cash flows, the full effect of falling prices may not be reflected in our estimated net cash flows for several quarters. We review the carrying value of our properties on a quarterly basis and once incurred, a write-down in the carrying value of our properties is not reversible at a later date, even if prices increase.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, increases in supplies from US shale production, international political conditions, including recent uprisings and political unrest in the Middle East and Africa, the European sovereign debt crisis, the domestic and foreign supply of oil and natural gas, the level of consumer demand due to slowing economic growth in China and continued weak economic growth in Europe, weather conditions, domestic and foreign governmental regulations and taxes, the price and availability of alternative fuels, the health of international economic and credit markets, the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") and other state-controlled oil companies to agree upon and maintain oil price and production controls, and general economic conditions. In addition, various factors, including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our oil and natural gas production. Any significant decline in the price of oil or natural gas would adversely affect our revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of our oil and natural gas properties and our planned level of capital expenditures including the development of the H_2S processing facility.

Increases in oil supplies from US shale production, coupled with slower economic growth in economies around the world and a decision by OPEC not to cut production to support higher oil prices, has led to a dramatic reduction in oil prices. While this fall in oil prices may escalate global economic growth rates, thereby increasing demand for oil supplies, the decline in oil prices may adversely affect our results of operations.

The increase in world oil supplies being produced, due to increased US shale production and OPEC's decision not to reduce production to support higher oil prices, occurring at the same time as reduced economic activity associated with slower economic growth in China, Europe and other global economies has reduced the demand for, and the prices we receive for, our oil and natural gas production. A sustained reduction in the prices we receive for our oil and natural gas production will have a material adverse effect on our results of operations and the borrowing base under our credit facility. A reduction in the borrowing base (e.g., a reduction in the estimated value of our assets) under our credit facility could mean a reduction in the capital available for investment in our oil and natural gas exploration and development activities in 2015 and could require mandatory loan repayment obligations under our credit facility.

The development plan for our proved undeveloped reserves may take longer, require higher levels of capital expenditures or be revised by us in a manner other than we currently plan due to factors beyond our control, which may require that we re-classify proved undeveloped reserves to an unproved category.

Approximately 60% of our total estimated proved reserves as of December 31, 2014, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations or successful construction of production facilities to treat H_2S produced along with oil. Subsequent to 2014 year end, as a result of the substantial recent fall in oil prices, we are considering reductions in our capital expenditures in connection with the processing facility, and there can be no assurances that the processing facility will be completed by 2017, if at all or that a more cost effective facility will re-establish production to all affected wells in the Ebouri and Etame fields. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves or a determination by us to not build and install the processing facility in order to re-establish production in the Ebouri and Etame fields could force us to reclassify certain of our proved reserves as unproved reserves.

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

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

We have identified material weaknesses in our internal control over financial reporting as of December 31, 2014, as disclosed in "Item 9A. Controls and Procedures". Failure to have effective internal controls could lead to a misstatement of our financial statements or prevent us from filing our financial statements in a timely manner. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial statements, our business decision processes may be adversely affected, our business and operating results could be harmed, investors could lose confidence in our reported financial information, the price of our common shares could decrease and our ability to obtain additional financing, or additional financing on favorable terms, could be adversely affected. In addition, failure to maintain effective internal control over financial reporting could result in investigations or sanctions by regulatory authorities.

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

Unless we are able to replace reserves which we have produced, our cash flows and production will decrease over time.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. There can be no assurance that our planned development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. In addition, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, material changes in oil or natural gas prices, prolonged periods of historically low oil and natural gas prices, failure of wells drilled in similar formations or delays in the delivery of equipment and availability of drilling rigs. Certain domestic oil and natural gas producing properties, as well as our Equatorial Guinea property are operated by third parties and, as a result, we have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

Our results of operations, financial condition, cash flows and compliance with debt covenants could be adversely affected by changes in currency exchange rates.

We are exposed to foreign currency risk from our foreign operations. While oil sales are denominated in U.S. dollars, portions of our operating costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing operating costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in recent years in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control. Our results of operations, financial condition, cash flows and compliance with debt covenants could be adversely affected by such fluctuations in currency exchange rates.

In addition, we entered into a credit facility in the first quarter of 2014 that includes financial covenants which could be affected by foreign currency exchange rates. Failure to maintain these covenants could preclude us from borrowing under our revolving credit facility and require us to immediately pay down any outstanding drawn amounts under the credit agreement, which could affect cash flows or restrict business. As of December 31, 2014, we were in compliance with all of our financial covenants under our credit facility.

Substantial capital, which may not be available to us in the future, is required to replace and grow reserves.

We make, and will continue to make, substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and natural gas reserves. Historically, we have financed these expenditures primarily with cash flow from operations, debt, asset sales, and private sales of equity. During 2014, we participated, and in 2015, we expect to continue to participate, in the further exploration and development projects on our international properties. In Gabon and Angola, we are the operator of the blocks and are thus responsible for contracting on behalf of all the remaining parties participating in the project. We rely on the timely payment of cash calls by our partners to pay for 69.95% of the offshore Gabon block budget, 50% of the onshore Gabon block budget and 50% of the offshore Angola block budget. The continued economic health of our partners could be adversely affected by low oil prices thereby adversely affecting their ability to make timely payment of cash calls.

However, if lower oil and natural gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to borrow funds, or our partners fail to pay their share of project costs, we may have a limited ability to expend the capital necessary to undertake or complete future drilling programs. We cannot assure you that the financing under our credit facility will be available in the future or that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Our drilling activities require us to risk significant amounts of capital that may not be recovered.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, equipment failures or accidents, elevated pressure or irregularities in geologic formations, compliance with governmental requirements and shortages or delays in the delivery of equipment and services.

Cyber-attacks targeting systems and infrastructure used by the oil and natural gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and natural gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and natural gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. While we have not experienced significant cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Our credit agreement imposes significant operating and financial restrictions on us that may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

Our credit agreement contains certain covenants that restrict our ability to take various actions, such as:

- requiring certain ratios with respect to debt service, field life and loan life coverage and liquidity;
- incur additional debt;
- make distributions or other restricted payments;
- make investments;
- enter into leases;
- use the proceeds of loans other than as permitted by the credit agreement;
- merge or consolidate or sell, transfer, lease or otherwise dispose of our assets;
- sell properties;
- agree to limit our ability to grant liens or pay dividends;
- enter into hedge agreements in excess of agreed limits;
- reduce certain working interests; and
- modify our organizational documents.

The restrictions contained in the credit agreement could:

- limit our ability to plan for or react to market conditions or meet capital needs or otherwise restrict our activities or business plans; and
- adversely affect our ability to finance our operations, strategic acquisitions, investments or alliances or other capital needs or to engage in other business activities that would be in our interest.

As of December 31, 2014, we believe we are in compliance with all of the financial covenants under our credit facility. Failure to maintain these covenants could preclude us from borrowing under our revolving credit facility and require us to immediately pay down any outstanding drawn amounts under the credit agreement, which could affect cash flows or restrict business.

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

Availability under our revolving credit facility is currently subject to a borrowing base of $65.0 million. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on the value of our oil and natural gas reserves as determined by the lenders under our credit facility, and other factors deemed relevant by our lenders. Recent declines in prices for oil and natural gas may cause our banks to reduce the borrowing base under our revolving credit facility. As of December 31, 2014, we had outstanding borrowings of $15.0 million which bore a weighted average interest rate of 4.32%. We intend to continue borrowing under our revolving credit facility in the future. However, the credit facility contains a covenant that prevents us from borrowing any amounts that would cause our debt to equity ratio to exceed 60:40. As of December 31, 2014, we estimate that this covenant would restrict our total borrowing capacity to approximately $25.0 million. Additionally, any significant reduction in our borrowing base as a result of borrowing base redeterminations, or otherwise, may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further if, the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we would be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our oil and natural gas activities.

The oil and natural gas business involves a variety of operating risks, including fire, explosions, blow-outs, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures and discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids including chemical additives, the occurrence of any of which could result in substantial losses to us due to injury and loss of life, 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. Our production facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling conducted by us overseas involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available at a reasonable cost or at all.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretive guidance on climate change disclosure, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities because of climate-related damages to our facilities and our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. If drought conditions were to occur, our ability to obtain water could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

We may not have enough insurance to cover all of the risks we face and operators of prospects in which we participate may not maintain or may fail to obtain adequate insurance.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations, production facilities, and other property, as well as injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, nationalization, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of oil and natural gas that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including unescalated prices and costs and capital expenditures subsequent to December 31, 2014, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and natural gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves incorporated by reference in this document. Specifically, the estimates for our reserves for the year ended December 31, 2014 included assumptions regarding capital expenditures to build the processing facility to remove H_2S and resume production in the Ebouri and Etame fields. Subsequent to 2014 year end, as a result of the substantial recent fall in oil prices, we are considering more cost efficient options, and there can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will re-establish production to all affected wells in the Ebouri and Etame fields. A determination to not build the processing facility in order to re-establish production or to build a more cost effective facility that does not re-establish all production from affected wells could force us to reclassify certain of our proved reserves in these fields as unproved reserves.

In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing oil and natural gas prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and natural gas industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of beginning of month prices received for oil and natural gas for the preceding twelve months. Future reductions in prices below the average calculated for 2014 would result in the estimated quantities and present values of our reserves being reduced.

A substantial portion of our proved reserves are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of oil and natural gas that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of oil and natural gas, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors do not affect estimates of U.S. reserves in the same way they affect estimates of proved reserves in foreign jurisdictions, or will have a different effect on reserves in foreign countries than in the United States. As a result, proved reserves in foreign jurisdictions may not be comparable to proved reserve estimates in the United States.

If oil and natural gas prices remain depressed for extended periods of time, we may be required to take write-downs in the value of our oil and natural gas properties.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using the un-weighted average price received for oil and natural gas based on closing prices on the first day of each month for the preceding twelve months from the date of the report. Prices for oil or gas at their current levels after the severe decline in prices in the second half of 2014 are currently below the average calculated for 2014. Because the undiscounted cash flows and discounted fair value related to the Etame, Ebouri and Southeast Etame/North Tchibala fields were less than the book values for these fields, the Company recorded an impairment of $98.3 million in the fourth quarter of 2014. Sustained lower prices will cause the estimated quantities and present values of our reserves being reduced and which may necessitate further write-downs.

We have less control over our foreign investments than domestic investments, and added risk in foreign countries may affect our foreign investments.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. For example, the Gabonese government has recently audited the accounts of a number of energy companies, including ours, that has led to disputes. The Gabonese government has formed a new oil company that

22

may seek to participate in oil and natural gas projects in a manner that could be dilutive to the interest of current license holders and the Gabonese government is under pressure from the Gabonese labor union to require companies to hire higher percentage of Gabonese citizens. In addition, if a dispute arises with our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the United States.

Private ownership of oil and natural gas reserves under oil and natural gas leases in the United States differs distinctly from our ownership of foreign oil and natural gas properties. In the foreign countries in which we do business, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the United States may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

Almost all of our proven reserves are located offshore of the Republic of Gabon. As of December 31, 2014, we carried an investment, before depletion and amortization, of approximately $168.5 million including leasehold and asset retirement obligations on our balance sheet associated with the Etame Marin block. We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

We have received an audit report related to our Etame Marin block operations from the Gabon Taxation Department, and an adverse result of the audit could result in a material liability and adversely affect our financial condition.

In October 2014, we received a provisional audit report related to our Etame Marine block operations from the Gabon Taxation Department as part of a special industry-wide audit of business practices and financial transactions in the Republic of Gabon. In November 2014, we responded to the Gabon Taxation Department requesting joint meetings to advance the resolution of this matter and provided a formal reply to the provisional audit report in February 2015. We currently cannot reasonably estimate a range of potential loss, if any, as a result of the audit. The ultimate outcome of the claim and impact cannot be predicted, and an adverse result of the audit could result in a material liability and adversely affect our financial condition.

Our operations may be adversely affected by violent acts such as from civil disturbances, terrorist acts, regime changes, cross-border violence, war, piracy, or other conflicts that may occur in regions that encompass our operations.

Violent acts resulting in loss of life, destruction of property, environmental damage and pollution occur around the world. Many incidents are driven by civil, ethnic, religious or economic strife. In addition, the number of incidents attributed to various terrorist organizations has increased significantly. We operate in regions of the world that have experienced such incidents or are in close proximity to areas where violence has occurred.

We monitor the economic and political environments of the countries in which we operate. However, we are unable to predict the occurrence of disturbances such as those noted above. In addition, we have limited ability to mitigate their impact.

Civil disturbances, terrorist acts, regime changes, war, or conflicts, or the threats thereof, could have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;

- negative impact on the world crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- inability of our personnel or supplies to enter or exit the countries where we are conducting operations;
- disruption of our operations due to evacuation of personnel;
- inability to deliver our production due to disruption or closing of transportation routes;
- reduced ability to export our production due to efforts of countries to conserve domestic resources;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- damage to or destruction of property belonging to our commodity purchasers leading to interruption of deliveries, claims of force majeure, and/or termination of commodity sales contracts, resulting in a reduction in our revenues;

- inability of our service and equipment providers to deliver items necessary for us to conduct our operations resulting in a halt or delay in our planned exploration activities, delayed development of major projects, or shut-in of producing fields;
- lack of availability of drilling rig, oilfield equipment or services if third party providers decide to exit the region;
- shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- capital market reassessment of risk and reduction of available capital making it more difficult for us and our partners to obtain financing for potential development projects.

Loss of property and/or interruption of our business plans resulting from civil unrest could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Competitive industry conditions may negatively affect our ability to conduct operations.

The oil and natural gas industry is intensely competitive. We compete with, and may be outbid by, competitors in our attempts to acquire exploration and production rights in oil and natural gas properties. These properties include exploration prospects as well as properties with proved reserves. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to retain and hire experienced personnel, especially for our engineering, geoscience and accounting departments;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and natural gas production; and
- the standards we establish for the minimum projected return on an investment of our capital.

Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do. These companies may be able to pay more for oil and natural gas properties, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit, and be better able than we are to continue drilling during periods of low oil and natural gas prices, to contract for drilling equipment and to secure trained personnel. Our competitors may also use superior technology which we may be unable to afford or which would require costly investment by us in order to compete.

The distressed financial conditions of customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers may experience, as a result of the severe decline in oil and natural gas prices in 2014 and in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

We may be unable to integrate successfully the operations of any acquisitions with our operations and we may not realize all the anticipated benefits of the recent acquisitions or any future acquisition.

Failure to successfully assimilate any acquisitions could adversely affect our financial condition and results of operations.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could result in material liabilities and adversely affect our financial condition.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every potential liability on each individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil and natural gas or the future operating or development costs of properties acquired;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the assumption of liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management’s attention from other business concerns;
- losses of key employees at the acquired businesses;
- operating a significantly larger combined organization and adding operations;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- coordinating or consolidating corporate and administrative functions.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

The laws and regulations of the United States, Gabon, Angola and Equatorial Guinea regulate our current business. Our operations could result in liability for personal injuries, property damage, natural resource damages, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators of properties that we purchase or lease. Some environmental laws provide for joint and several strict liabilities for remediation of releases of hazardous substances, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases and use of hydraulic fracturing fluids, resulting in increased operating costs. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition, results of operations and liquidity. Additionally, more stringent GHG regulation could impact demand for oil and natural gas.

These laws and governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. While we believe that we are currently in compliance with environmental laws and regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

If our assumptions underlying accruals for abandonment costs are too low, we could be required to expend greater amounts than expected.

Almost all of our producing properties are located offshore. The costs to abandon offshore wells may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred by capitalizing it as part of the carrying amount of the long-lived assets. No assurances can be given that such reserves will be sufficient to cover such costs in the future as they are incurred.

As part of securing the first of two five-year extensions in 2011 to the Etame field production license to which the Company is entitled from the government of Gabon, the Company agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin Block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over the remaining life of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The initial funding took place in October 2014 for calendar years 2012 and 2013 totaling \$8.4 million (\$2.3 million net to the Company). The funding for calendar year 2014 was paid in the first quarter of 2015 in the amount of \$4.2 million (\$1.2 million net to the Company). As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company's balance sheet. The cash funding is reflected under other long term assets as "Abandonment Funding".

From time to time we may hedge a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and natural gas.

We may reduce our exposure to the volatility of oil and natural gas prices by hedging a portion of our production. Hedging also prevents us from receiving the full advantage of increases in oil or natural gas prices above the maximum fixed amount specified in the hedge agreement. Conversely, hedging may limit our ability to realize cash flows from commodity price increases. In a typical hedge transaction, we have the right to receive from the hedge counterparty the excess of the maximum fixed price specified in the hedge agreement over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the maximum fixed price, we must pay the counterparty this difference multiplied by the quantity hedged even if we had insufficient production to cover the quantities specified in the hedge agreement. Accordingly, if we have less production than we have hedged when the floating price exceeds the fixed price, we must make payments against which there are no offsetting sales of production. If these payments become too large, the remainder of our business may be adversely affected.

The distressed financial conditions of one or more hedge providers could have an adverse impact on us in the event these hedge providers are unable to pay us amounts owed to us under one or more financial hedge transactions by which we have hedged our exposure to commodity price volatility.

From time to time, we enter into financial hedge transactions to hedge or mitigate our exposure to the risks of commodity price volatility with respect to the crude oil or natural gas we produce and sell. Similarly, some credit agreement facilities will require that we enter into financial hedges with creditworthy hedge providers for a percentage of our anticipated oil and natural gas production in order to ensure that we are able to make debt service payments under such credit facilities if oil and natural gas prices fall. In such instances, the hedge provider will be obligated to make payments to us under such financial hedge transactions to the extent that the floating (market) price is below an agreed fixed (strike) price. During periods of falling commodity prices, including the recent severe decline in oil and natural gas prices, some of our hedge providers may experience, in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed hedge providers will not default on their obligations to make a payment owed to us or that such a default or defaults will not have a material adverse effect on our business, financial position, and future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our hedge providers or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities. In addition, such events might force such hedge providers to reduce or curtail their future level of financial hedge availability (liquidity) to us, which could have a material adverse effect on our results of operations and financial condition and could have a material adverse effect on one or more of our credit agreement facilities. In addition, hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations. This risk of counterparty performance is of particular concern given the disruptions that have occurred in the financial markets that led to sudden changes in counterparty’s liquidity and hence their ability to perform under their hedging contracts with us. We are unable to predict sudden changes in counterparty’s creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on the Company's ability to use financial derivative instruments to reduce (hedge, manage or mitigate) the effect of commodity price, interest rate, and other cost volatilities associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), signed into law in 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives markets and entities, such as us, that participate in those markets. The Dodd-Frank Act required the Commodities Futures Trading Commission ("CFTC") and the Securities and Exchange Commission ("SEC") to promulgate rules and regulations implementing the new legislation; although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on November 5, 2013, a proposed rule imposing position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain specified types of hedging transactions are exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, the CFTC has issued a proposed rule on Margin requirements, which proposes to exempt commercial end-users entering into uncleared swaps in order to hedge commercial risks affecting their business from any requirement to post margin to secure their swap transactions that are hedging commercial risks. In addition, the CFTC has issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a derivatives clearing organization and to trade all such swaps on an exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or margin requirements, depending on our ability to satisfy the CFTC's requirements for a commercial end-user using swaps to hedge or mitigate our commercial risks, these rules and regulations may require us to comply with position limits, margin requirements and with certain clearing and trade-execution requirements in connection with our financial derivative activities. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of commercial end-users to have access to financial derivatives to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our ability to hedge risks and on our consolidated financial position, results of operations, or cash flows.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.

In recent years, the current U.S. government's budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and natural gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect our financial condition and results of operations.

We rely on our senior management team and the loss of a single member could adversely affect our operations.

We are highly dependent upon our executive officers and key employees. The unexpected loss of the services of any of these individuals could have a detrimental effect on us. These individuals have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties and developing and executing financing and hedging strategies. We do not maintain key man life insurance on any of our employees.

We rely on a single purchaser of our Gabon production, which could have a material adverse effect on our results of operations.

Effective January 2011, we sold all of our crude oil production in Gabon to Mercuria, and the contract with Mercuria was extended through the first quarter of 2014. In Gabon, starting in the second quarter of 2014, the Company switched to an agency model to sell its crude oil. The Company contracted with a third party in order to sell, based on a fixed barrel fee, on the spot market. For the first quarter of 2015, the Company will also sell its oil under the agency model on the spot market.

The marketability of our production in Texas is dependent upon transportation and processing facilities over which we may have no control.

The marketability of our production from Texas depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through gathering systems and pipelines, some of which we do not own. The lack of availability of capacity on third-party systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, including adverse weather conditions. Activist or other efforts may delay or halt the construction of additional pipelines or facilities.

Third-party systems and facilities may not be available to us in the future at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could delay production, thereby harming our business and, in turn, our financial condition, results of operations and cash flows.

Additionally, the price and terms for access to pipeline transportation in the U.S. remain subject to extensive federal and state regulation. If these regulations change, or if rate increase requests are approved, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity. Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we cannot provide assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. In past sessions, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local jurisdictions including Texas, where we operate, have adopted, or are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York recently has announced that it will impose a ban on high-volume hydraulic fracturing. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. Further, the EPA has announced an initiative under TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations to address wastewater from hydraulic fracturing operations. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Additionally, a number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have adversely impacted drinking water supplies, use of surface water, and the environment generally. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

Our management, including our Chief Executive Officer and Chief Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties
Offshore Gabon- Etame Marin Block

VAALCO has an interest in an approximately 28,700 gross acre offshore block in Gabon, the Etame Marin block, where it signed a production sharing contract in 1995. The block contains the Etame, Avouma, South Tchibala and Ebouri fields, all of which are in production, and the Southeast Etame/North Tchibala field, which are currently being developed. These fields and discoveries consist of subsalt reservoirs that lie 20 miles offshore in water depths of approximately 250 feet.

VAALCO operates the Etame Marin block on behalf of a consortium of companies. The Company owns a 28.1% interest in the development areas in and surrounding the Etame, Avouma/South Tchibala and Ebouri fields. The development areas were subject to a 7.5% back-in by the Government of Gabon, which occurred for these fields after their successful development. The Government of Gabon has since assigned the back-in interest to a third party. The Southeast Etame/North Tchibala field will also be subject to the 7.5% back in by the Government of Gabon.

The Etame Marin block consortium approved the development of the Etame field in 2001. An application for commerciality was filed with the government of Gabon, and in July 2001 the consortium was awarded an approximately 12,000 gross acre exploitation area surrounding the field. The exploitation area has a term of 20 years through June 2021 (a ten year primary term followed by two subsequent five year renewals) and also includes the Southeast Etame field currently being developed.

The development of the Etame field included drilling and completing subsea wells connected to a contracted floating production, storage and offloading vessel (“FPSO”). More recently, in the third quarter of 2014, the Company installed a platform in approximately 250 feet of water and in the fourth quarter of 2014 commenced drilling of two development wells from the platform. The development wells are tied back to the FPSO via a pipeline. There are currently four wells producing in the Etame field.

In April 2005, a development plan for the joint development of the Avouma/South Tchibala field was approved by the Gabon government. The Company was awarded an approximately 13,000 gross acre exploitation area which has a term of 20 years through March 2025 (a ten year primary term followed by two subsequent five year renewals). In 2006, the Company installed a platform in approximately 250 feet of water and drilled development wells from the platform. Three wells are currently producing in the South Tchibala/Avouma field. A well in the Avouma field is temporarily not producing oil as it is waiting on a workover to replace an in-line valve and potentially the failed electrical submersible pumps. The development wells are tied back to the FPSO via a ten mile pipeline.

The Company drilled the Ebouri discovery well to total depth in January 2004. In October 2006, the Gabon government approved the development plan for the Ebouri field and the Company was awarded an approximately 3,700 gross acre exploitation area which has a term of 20 years through July 2026 (a ten year primary term followed by two subsequent five year renewals). A platform was installed in July 2008, approximately seven miles from the FPSO and is tied back to the FPSO via a pipeline as was done for the Avouma/South Tchibala field. The first development well began production in January 2009 and the second development well began producing crude oil in April 2009. A third development well began production in May 2010. There is currently one producing well in the Ebouri field.

In July 2012, the Company discovered the presence of hydrogen sulfide (“H_2S”) from two of the three producing wells in the Ebouri field. The wells were shut-in for safety and marketability reasons resulting in a decrease of approximately 2,000 BOPD or approximately 10% of the gross daily production from the Etame Marin block at that time. In addition, H_2S was first detected in January 2014 and later confirmed in July 2014 in the Etame 5-H well in the Etame field, and this well has also been shut-in. Analysis and options for re-establishing production from the impacted areas continued through the fourth quarter of 2014. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including a processing facility capable of removing H_2S, recompletion of the temporarily abandoned wells, and potentially, additional new wells. Considering the substantial recent fall in oil prices, the Company and its partners are focusing on more cost efficient options for a processing facility (e.g. chemical removal options, construction of a smaller facility on existing structures, or the use of surplus equipment and used structures). There can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will cover all affected areas of the Ebouri and Etame fields. It is expected that the timing of the project startup will be known as early as the fourth quarter of 2015 with a goal of re-establishing production from the area impacted by H_2S as soon as practical. Should the Company and its partners evaluation result in no economic alternative, a decrease of as much as 2.4 million barrels of proved undeveloped reserves could result.

The Company and its partners approved the construction of two additional production platforms in late 2012 as part of future development plans for the Etame Marin block. The construction of the two new platforms began in the first quarter of 2013 and were installed in the third quarter of 2014. One platform was installed in the Etame field and the second platform was installed between the Southeast Etame/North Tchibala field. The Company contracted a drilling rig to commence a multi-well development drilling program, which moved onto location and began drilling the first well in November 2014 from the Etame platform, in the Etame field. The Company drilled a successful exploration well in the Southeast Etame area in 2010 which is expected to be developed from the second platform in 2015. The total cost to build and install the two platforms was $351.0 million ($106.5 million net to the Company). The cost of the wells is not included in the platform costs.

The sixth extension of the exploration acreage on this block expired at the end of July 2014. The Company fully met all of the obligations under the terms of the sixth extension period. In the second quarter of 2014, and prior to the deadline, the Company and its partners submitted a proposal for a seventh exploration license. The Government of Gabon responded in the first quarter of 2015 that a seventh exploration license would require a separate production sharing contract ("PSC") and this requirement is being evaluated by the Company and its partners.

Late in 2012, a drilling and workover campaign began with the arrival of a drilling rig to conduct a six well program that was ultimately increased to an eight well program extending into 2014. The early-2014 program included the drilling of an exploration well that did not discover commercial quantities of hydrocarbons. Accordingly, the Company expensed $1.9 million of incurred dry hole costs in the fourth quarter of 2013 for this well, with the remainder of $11.7 million of dry hole costs expensed in the first quarter of 2014. The Company performed a workover to replace the electrical submersible pumps in a well in the Avouma field in the first quarter of 2014 and in May 2014 brought on production a development well drilled in the South Tchibala field to replace a well with damaged casing.

Following the installation of the two additional platforms in the third quarter of 2014, the Company and its partners began a development well drilling campaign beginning in October 2014 from the Etame platform. The first well drilled, the Etame 8-H well, was completed in December 2014 and was shut-in as the well was determined to be producing H_2S during the initial testing process. The Company is planning to conduct an extended well test of the Etame 8-H well, to confirm and quantify the presence of H_2S which was detected during the initial 17 hour flow test. The well test is expected to occur in the first half of 2015. In December 2014, the Company spudded the Etame 10-H well which was drilled to the 1-V fault block, and the well was brought on production in the first quarter of 2015. The Etame 10-H well confirmed the presence of an undrained lower lobe of the Gamba reservoir in this fault block with no H_2S present. Additional development wells are expected to be drilled in 2015 from the two platforms.

As part of securing the first of two five-year extensions in 2011 to the Etame field production license to which the Company is entitled from the government of Gabon, the Company agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin Block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over the remaining life of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The initial funding took place in October 2014 for calendar years 2012 and 2013 totaling $8.4 million ($2.3 million net to the Company). The funding for calendar year 2014 was paid in the first quarter of 2015 in the amount of $4.2 million ($1.2 million net to the Company). As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company's balance sheet. The cash funding is reflected under other long term assets as "Abandonment Funding".

In the fourth quarter of 2014, the Company recorded an impairment loss of $98.3 million to write down its investment in certain fields comprising the Etame Marin Block, offshore Gabon to its fair value. An impairment of $38.5 million was recorded in the Etame field, $5.9 million in the Ebouri field and $53.9 million in the Southeast Etame/North Tchibala field. The impairment is a result of the recent decline in the forecasted oil prices used in the impairment testing and calculation.

Onshore Gabon - Mutamba Iroru block

In November 2005, the Company signed a production sharing contract for the Mutamba Iroru block onshore Gabon. The five year contract awarded the Company exploration rights to approximately 270,000 acres along the central coast of Gabon. The Company acquired aeromagnetic gravity data in 2008, and together with seismic data acquired from previous operators over the block in 2006 and 2007, drilled two exploration wells in 2009. Both wells encountered water bearing sands and were abandoned.

The Company executed a farm-out agreement in August 2010 with Total Gabon on the Mutamba Iroru block located onshore near the coast in central Gabon. Under the terms of the agreement, the Company and Total Gabon committed to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. The seismic reprocessing work was completed in 2012. The exploration well was drilled in 2012 resulting in a discovery. In return for funding 75% of the work commitment (seismic reprocessing and exploration well costs), Total Gabon earned a 50% interest on the permit.

A revised production sharing contract ("PSC") including exploration rights is in the approval process. The term sheet, which specifies financial and other obligations to be included in the PSC, was agreed to and signed by the Company, its joint venture partner, and the Government of Gabon on July 31, 2014. The form of the PSC has been completed and presented to the Company and its joint venture partner for execution. The joint venture partner has withheld its approval of the new PSC pending resolution of certain legal aspects of the new agreement with the Government of Gabon. In March 2015, the joint venture partner indicated to the Company that the legal aspects have not yet been resolved to their satisfaction. The Company can provide no assurance as to the joint venture partner approving the PSC. The Company remains committed to this block and further meetings of the parties are expected to occur in the first half of 2015.

After the PSC is approved, an application for a development area will be made by the Company. After issuance of a development area, the next step is the submittal of the plan of development. The Company can provide no assurances as to the either the approval of the PSC by the Government of Gabon, or the subsequent approval of a development area by the Government of Gabon.

Development of the onshore block is expected to capitalize on synergies such as experienced personnel from our operating base office space, warehouse and open yard space in Port Gentil, Gabon.

Offshore Angola – Block 5

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term, with an optional three year extension, awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract, the Company had commitments to acquire and process seismic and drill two exploration wells. The seismic commitments were met within the time period, but the wells were not drilled due to partner non-performance.

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Additional extensions were subsequently granted by the Angolan government until November 30, 2014 to drill the two exploration commitment wells.

In the fourth quarter of 2013, the Company received a written confirmation from The Ministry of Petroleum of Angola that the available 40% working interest in Block 5, offshore Angola, has been assigned to Sonangol E.P., the National Concessionaire. The Ministry of Petroleum also confirmed that Sonangol E.P. would assign the aforementioned participating interest to its exploration and production affiliate, Sonangol P&P. The assignment was made effective on January 1, 2014. The unpaid amounts from the defaulted partner plus the amounts incurred on partner behalf during the period prior to assignment of the working interest to Sonangol P&P are believed by the Company to be the responsibility of the acquirer of the working interest. The Company invoiced Sonangol P&P for these amounts totaling $7.6 million plus interest in April 2014. Due to the uncertainty of collection, the Company has recorded a full allowance totaling $7.6 million during 2011 through 2013 for the amount owed to the Company above its 40% working interest plus the 10% carried interest.

In April 2014, the Company received a letter and contractual amendment proposal from Sonangol E.P., the national oil company in Angola related to the extension of the two well drilling commitment. Due to the uncertainty that the primary term of the exploration license would be extended by the Republic of Angola in accordance with the contractual amendment proposal before the November 30, 2014 expiration date, in October 2014, the Company entered into the Subsequent Exploration Phase ("SEP"), together with its working interest partner, Sonangol P&P. The SEP option was provided for in the Production Sharing Agreement signed in 2006 with the Republic of Angola. The SEP extends the exploration period for an additional three year period such that the new expiry date for exploration activities is November 30, 2017. Entering the SEP requires the Company and its partner to acquire 3D seismic covering six hundred square kilometers and to drill two additional exploration wells. The Company has already satisfied the seismic obligation of the SEP with the purchase of 3D seismic in the outboard segment of the block in late 2013, which is currently being processed and will continue to be processed into 2015.

By entering into the SEP, the Company is required to drill a total of four exploration wells during the exploration extension period. The four well obligations include the two well commitments under the primary exploration period that carries over to the SEP period. A $10.0 million dollar assessment ($5.0 million dollars net to VAALCO) applies to each of the four commitment exploration wells, if any, that remain undrilled at the end of the exploration period in November 2017. Restricted cash of $10.0 million for the two new commitment wells was recorded in the fourth quarter of 2014. At December 31, 2014 the Company had $20.0 million in restricted cash related to the offshore Angola exploration agreement.

A drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well began drilling in the first quarter of 2015. Drilling this well satisfies one of the four exploration well obligations and will release $5.0 million of the $20.0 million recorded as restricted cash at December 31, 2014 by the Company.

Offshore Equatorial Guinea - Block P

In July 2012, the Company signed a definitive agreement with Petronas Carigali Overseas SDN BHD for the purchase of a 31% working interest in Block P, located offshore Equatorial Guinea for 57,000 acres at a cost of $10.0 million. The acquisition was completed on November 1, 2012. GEPetrol, the national oil company of Equatorial Guinea, is the operator of the block. During 2014, the Company and GEPetrol continued to work on a joint operatorship model whereby the Company would have a significant role in operator activities on the block. Additionally, the Company has been working with the Ministry of Mines, Industry and Energy regarding timing and budgeting for development and exploration activities.

Onshore Domestic - Texas

The Company acquired a 640 acre lease in the Hefley field (Granite Wash formation) in North Texas in December 2010 and a 480 acre lease in the same formation in July 2011. The first well drilled in the Hefley field began production in August 2011. Production from the second well drilled began in April 2012. During 2014, the two wells produced approximately 3,000 Bbls of condensate and 200 million cubic feet of gas net to the Company after deduction of royalty and severance taxes. Financial impairments totaling $12.6 million were recorded for the Hefley field in 2011 and 2012 on the basis of production performance, projected hydrocarbon price curves, operating expenses and estimated reserves. In the second half of 2013, the Company expensed the remaining unevaluated leasehold costs of the two leases totaling $2.6 million. No capital expenditures occurred in 2014 and no additional capital expenditures are anticipated in 2015 for this property.

Onshore Domestic - Montana

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. The working interest was subsequently reduced to 50% and 11,000 net acres in December 2012. Pursuant to the terms of the acquisition, the Company was required to drill three wells at its sole cost. The first of the two wells drilled were unsuccessful efforts, resulting in dry hole costs and leasehold impairment totaling $18.4 million recorded in the fourth quarter of 2012. The third well which was drilled in the fourth quarter of 2012 at a cost of $3.0 million was charged to dry-hole expense in the third quarter of 2013. The remaining carrying value of the undeveloped acreage of this property is $1.3 million and is held by production. No capital expenditures occurred in 2014, and no capital expenditures are anticipated for this property in 2015.

Domestic – Outside Operated

The Company has minor interests in Brazos County, Texas producing from the Buda/Georgetown formations. The Company also owns certain minor non-operated interests in the Ship Shoal area of the Gulf of Mexico and in Pickens County, Alabama. During 2014, these wells produced approximately 100 Bbls of oil and 5 million cubic feet of gas net to the Company. No significant activity was undertaken on these properties in 2014 and no capital expenditures are anticipated in 2015 for these properties.

Sales Volumes, Prices, and Production Costs

Sales volumes, prices, and production costs (net to the Company) for the Company's operations for the years 2014, 2013, and 2012 are shown below.

	Year Ended December 31,								
	2014			2013			2012		
	Oil Equivalent	Oil	Gas	Oil Equivalent	Oil	Gas	Oil Equivalent	Oil	Gas
Aggregate production									
(Oil equivalent in MBOE, Oil in MBbl, gas in MMcf)									
Etame	639	639	-	790	790	-	800	800	-
Avouma/S.Tchibala	511	511	-	488	488	-	493	493	-
Ebouri	198	198	-	266	266	-	438	438	-
Hefley Field, USA (1)	40	3	222	57	5	316	96	10	519
Other USA properties	1	-	5	2	-	9	3	1	12
Total production	1,389	1,351	227	1,603	1,549	325	1,829	1,741	532
Average Sales Price ($/unit)									
Etame	$93.68	$93.68	$-	$108.42	$108.42	$-	$111.24	$111.24	$-
Avouma/S.Tchibala	$93.68	$93.68	-	108.42	108.42	-	111.24	111.24	-
Ebouri	$93.68	$93.68	-	108.42	108.42	-	111.24	111.24	-
Hefley Field, USA(1)	32.44	85.89	4.60	31.90	85.24	4.53	28.06	81.68	3.69
Other USA properties	30.87	100.39	3.48	31.72	86.10	3.61	28.53	94.24	2.44
Total average sales price ($/unit)	$91.86	$93.66	$4.57	$105.60	$108.35	$4.50	$106.75	$111.06	$3.66
Average Production Cost ($/unit)(2)									
Etame	$23.01	$23.01	$-	$23.63	$23.63	$-	$14.82	$14.82	$-
Avouma/S.Tchibala	23.01	23.01	-	23.63	23.63	-	14.82	14.82	-
Ebouri	23.01	23.01	-	23.63	23.63	-	14.82	14.82	-
Hefley Field,USA(1)	9.97	9.97	1.69	1.80	1.80	0.30	9.13	9.13	1.52
Other USA properties	6.42	6.42	1.07	13.06	13.06	2.18	9.56	9.56	1.59
Total average production cost ($/unit)	$22.62	$22.62	$3.84	$22.84	$22.84	$3.81	$14.61	$14.61	$2.43

(1) The Hefley field is in the Granite Wash formation, in North Texas.
(2) Production cost in $/unit is the ratio of the Company's production cost over units of production.

RESERVE INFORMATION

The table below sets forth the Company's estimated net proved reserves for the years ended December 31, 2014, 2013, and 2012 as prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers. There have been no estimates of total proved net oil or gas reserves filed with or included in reports to any federal authority or agency other than the SEC since the beginning of the last fiscal year. International reserves are located in the Etame Marin block offshore Gabon. Domestically, reserves are located in Texas (onshore), Louisiana (offshore) and Alabama (onshore). Reserves estimated by our independent engineers at December 31, 2014, 2013, and 2012 reflect oil and natural gas spot prices based on the average prices during the 12-month period before the ending date of the period covered by this report determined as an unweighted, arithmetic average of the first-day-of-the-month price for each month within such period.

	As of December 31,		
	2014	2013	2012
Crude Oil			
Proved Developed Reserves (MBbls)			
United States	27	26	33
International	3,197	3,279	3,717
Total Proved Developed Reserves (MBbls)	3,224	3,305	3,750
Proved Undeveloped Reserves (MBbls)			
United States	-	-	-
International	5,036	3,927	3,738
Total Proved Undeveloped Reserves (MBbls)	5,036	3,927	3,738
Total Proved Reserves (MBbls)			
United States	27	26	33
International	8,233	7,206	7,455
Total Proved Reserves (MBbls)	8,260	7,232	7,488
Natural Gas			
Proved Developed Reserves (MMcf)			
United States	1,406	1,333	1,544
International	-	-	-
Total Proved Developed Reserves (MMcf)	1,406	1,333	1,544
Proved Undeveloped Reserves (MMcf)			
United States	-	-	-
International	-	-	-
Total Proved Undeveloped Reserves (MMcf)	-	-	-
Total Proved Reserves (MMcf)			
United States	1,406	1,333	1,544
International	-	-	-
Total Proved Reserves (MMcf)	1,406	1,333	1,544
Standardized measure of proved reserves (in thousands)	$149,387	$137,436	$152,902

Proved Undeveloped Reserves

The Company annually reviews all proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. The Company's PUDs are generally expected to be converted to proved developed reserves within five years of the date they are first booked as PUDs. However, lower prices for oil and natural gas as seen in the recent decline may cause the Company in the future to forecast less capital to be available for development of its proved undeveloped reserves in the future, which will cause the Company to decrease the amount of its proved undeveloped reserves it expects to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause the Company's proved undeveloped reserves to become uneconomic to develop, which would cause it to remove them from the proved undeveloped category. Specifically, the estimates of the Company's reserves for the year ended December 31, 2014 included assumptions regarding capital expenditures to build the processing facility to remove H_2S and resume production from certain wells in the Ebouri and Etame fields. Subsequent to 2014 year end, as a result of the substantial recent fall in oil prices, the Company is considering more cost efficient options, and there can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will cover all affected areas of the Ebouri and Etame fields. A determination to not build the processing facility, or to build a more cost effective facility, could force the Company to reclassify certain of its PUDs in these fields as unproved reserves.

The Company had 5,036 MBbls of PUD's at December 31, 2014 compared with 3,927 MBbls of PUD's at December 31, 2013. Approximately 3.5 million barrels of the PUD's are related to the construction of the two new platforms for Etame and Southeast Etame/North Tchibala (2.4 MBbls and 1.1 MBbls of PUD's respectively). Approximately 1.1 MBbls of PUD's are associated with the Ebouri field. The remaining 0.4 MBbls of PUD's associated with the Avouma/South Tchibala field. The table below shows the years that the existing PUD's (MBbls) were booked (unaudited).

Year	Etame	Avouma/South Tchibala	Ebouri	Southeast Etame/North Tchibala
2009	0.4	-	0.7	-
2010	0.4	-	-	-
2011	-	-	-	-
2012	0.4	-	0.7	1.1
2013	0.2	-	-	-
2014	1.0	0.4	(0.3)	-
Total	2.4	0.4	1.1	1.1

All of the reserves at Ebouri, and a portion of the reserves in the main fault block at Etame may be sour, and the development of these reserves is dependent upon the installation of processing facilities to remove H_2S.

Elaborating, in July 2012, the Company discovered the presence of hydrogen sulfide ("H_2S") from two of the three producing wells in the Ebouri field. The wells were shut-in for safety and marketability reasons resulting in a decrease of approximately 2,000 BOPD or approximately 10% of the gross daily production from the Etame Marin block at that time. In addition, H_2S was first detected in January 2014 and later confirmed in July 2014 in the Etame 5-H well in the Etame field, and this well has also been shut-in. Analysis and options for re-establishing production from the impacted areas continued through the fourth quarter of 2014. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including a processing facility capable of removing H_2S, recompletion of the temporarily abandoned wells, and potentially, additional new wells. Considering the substantial recent fall in oil prices, the Company and its partners are focusing on more cost efficient options for a processing facility (e.g. chemical removal options, construction of a smaller facility on existing structures, or the use of surplus equipment and used structures). There can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will cover all affected areas of the Ebouri and Etame fields. It is expected that the timing of the project startup will be known as early as the fourth quarter of 2015 with a goal of re-establishing production from the area impacted by H_2S as soon as practical. Should the Company and its partners evaluation result in no economic alternative a decrease of as much as 2.4 million barrels of proved undeveloped reserves could result at Etame and Ebouri.

The Company does not have any PUD's associated with its United States operations.

Controls Over Reserve Estimates

The Company's policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. Compliance with these rules and regulations with respect to the Company's reserves is the responsibility of the Company's reservoir engineer, who is the Company's principal engineer. The Company's principal engineer has over 20 years of experience in the oil and gas industry, including over 10 years as a reserve evaluator, trainer or manager and is a qualified reserves estimator, as defined by the Society of Petroleum Engineers' standards. Further professional qualifications include a Bachelor's and Master's degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and has been a member of the Society of Petroleum Engineers for over 20 years.

The Company's controls over reserve estimates included retaining NSAI as our independent petroleum and geological firm. The Company provided information about the Company's oil and gas properties, including production profiles, prices and costs, to NSAI and they prepare their own estimates of the reserves attributable to our properties. All of the information regarding reserves in this annual report on Form 10-K is derived from the report of NSAI. The report of NSAI is included as an exhibit to this annual report on Form 10-K.

The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. John Cliver and Mr. Patrick Higgs. Mr. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. He graduated from Rice University in 2004 with a Bachelor of Science Degree in Chemical Engineering and from University of Texas at Austin in 2008 with a Master of Business Administration Degree. Mr. Higgs, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1996 and has over 20 years of prior industry experience. He graduated from Texas A&M University in 1976 with a Bachelor of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Audit Committee of the Board of Directors meets with management, including the Company’s principal engineer, to discuss matters and policies related to reserves.

The following tables set forth the net proved reserves of the Company as of December 31, 2014, 2013 and 2012, and the changes during such periods.

Proved Reserves:	Oil (MBbls)	Gas (MMCF)
Balance at January 1, 2012	6,048	1,925
Production	(1,741)	(532)
Revisions of previous estimates	2,200	151
Extensions and discoveries	981	-
Balance at December 31, 2012	7,488	1,544
Production	(1,549)	(325)
Revisions of previous estimates	771	114
Extensions and discoveries	522	-
Balance at December 31, 2013	7,232	1,333
Production	(1,351)	(227)
Revisions of previous estimates	2,312	300
Extensions and discoveries	67	-
Balance at December 31, 2014	8,260	1,406

Proved Developed Reserves	Oil (MBbls)	Gas (MMCF)
Balance at January 1, 2012	3,854	856
Balance at December 31, 2012	3,750	1,544
Balance at December 31, 2013	3,305	1,333
Balance at December 31, 2014	3,224	1,406

The Company does not book proved reserves on discoveries until such time as a development plan has been prepared and approved by the Company’s partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

The Company's proved developed reserves are located offshore Gabon and in Alabama, Texas and waters of the Gulf of Mexico. Revisions in 2014 were primarily due to better reservoir performance at the Avouma/South Tchibala field (1,507 MBbls) and a combination of better reservoir performance from existing wells at Etame, and revisions to proved undeveloped reserves at Etame (1,122 MBbls). Ebouri proved undeveloped reserves were revised downward (300 MBbls) due to higher costs of developing the reserves rendering them uneconomic. Revisions in 2013 were primarily due to better reservoir performance at the Etame field (800 MBbls). In 2012, the revisions were due to improved reservoir performance at the Avouma/South Tchibala field (1,200 MBbls) and improved reservoir performance at Etame (1,000 MBbls). In 2014, the extensions and discoveries were associated with the booking of the Southeast Etame/North Tchibala reserves. Extensions and discovery reserve additions in 2013 were due to the drilling of the Avouma 3H well which extended the reservoir boundary further to the north at the Avouma field. In 2012, the extensions and discoveries were associated with the booking of the Southeast Etame/North Tchibala reserves following approval of the development plans for these fields and final investment decision to install the platforms necessary to develop these fields.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the Company. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place remain the property of the Gabon government.

In accordance with the current guidelines of the SEC, the Company's estimates of future net cash flow from the Company's properties and the present value thereof are made using oil and gas contract prices using a twelve month average price and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. In Gabon, the 12-month weighted average price of oil as of December 31, 2014, was $98.88 per Bbl. In the United States, the 12-month weighted average price as of December 31, 2014, was $86.49 per Bbl of condensate and $5.193 per Mcf of gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Prices for oil or gas at their current levels after the severe decline in the second half of 2014 are currently below the average calculated for 2014, and sustained lower prices will cause the twelve month weighted average price to decrease over time as the lower prices are reflected in the average price, resulting in the estimated quantities and present values of the Company's reserves being reduced.

Additionally, the estimates for the Company's reserves for the year ended December 31, 2014 included assumptions regarding capital expenditures to build the processing facility to remove H_2S and resume production from certain wells in the Ebouri and Etame fields. Subsequent to 2014 year end, as a result of the substantial recent fall in oil prices, the Company is considering more cost efficient options, and there can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will cover all affected areas of the Ebouri and Etame fields. A determination to not build the processing facility or to build a more cost effective facility could cause the Company to reclassify certain of its PUDs in these fields as unproved reserves.

Drilling History

In 2014, the Company drilled three wells and completed one well reported in 2013 as being in-progress as follows: one development well offshore Gabon in the Avouma/South Tchibala field (productive), two developments wells offshore Gabon in the Etame field (in-progress) and one exploratory well offshore Gabon (dry, reported as being in-progress at the end of 2013).

	Domestic						International					
	Gross			Net			Gross			Net		
	2014	2013	2012	2014	2013	2012	2014	2013	2012	2014	2013	2012
Exploratory Wells												
Productive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.5
Dry	0.0	2.0	4.0	-	1.7	3.3	1.0	2.0	0.0	0.4	0.6	0.0
In progress	0.0	0.0	1.0	0.0	0.0	0.7	0.0	1.0	0.0	0.0	0.4	0.0
Development Wells												
Productive	0.0	0.0	1.0	0.0	0.0	1.0	1.0	1.0	0.0	0.3	0.3	0.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

In progress	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.6	0.0	0.0
Total Wells	0.0	2.0	6.0	0.0	1.7	5.0	4.0	4.0	1.0	1.3	1.3	0.5

Acreage and Productive Wells

Below is the total acreage under lease and the total number of productive oil and gas wells of the Company as of December 31, 2014:

	United States		International	
	Gross	Net (1)	Gross	Net (1)
	(Acreage in thousands)			
Developed acreage	7.9	1.4	28.7	8.1
Undeveloped acreage	23.1	11.9	1,727.0	688.0
Productive gas wells	5.0	2.1	0.0	0.0
Productive oil wells	4.0	0.8	7.0	2.0

(1) Net acreage and net productive wells are based upon the Company's working interest in the properties. The Company's share of net developed acreage offshore Gabon is 8,100 acres. The Company has net undeveloped acreage of 560,000 acres in Angola, 110,000 acres onshore Gabon and 18,000 acres in Equatorial Guinea.

Office Space

The Company leases its offices in Houston, Texas (approximately 22,023 square feet), and in Luanda, Angola (approximately 2,500 square feet), and in the first quarter of 2014, the Company bought the office space in Port Gentil, Gabon (approximately 20,925 square feet) which management believes are adequate for the Company's operations. The office space in Port Gentil, Gabon was purchased by the Company in the first quarter of 2014.

Item 3. Legal Proceedings

The Company is currently not a party to any material litigation.

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

General

The Company's common stock is traded on the New York Exchange under the symbol EGY. The following table sets forth the range of high and low sales prices of the common stock for the periods indicated.

Period	High	Low
2014:		
First Quarter	$8.55	$5.93
Second Quarter	9.22	6.29
Third Quarter	9.42	6.77
Fourth Quarter	8.68	4.14
2013:		
First Quarter	$9.42	$7.57
Second Quarter	7.50	5.46
Third Quarter	6.43	5.28
Fourth Quarter	7.18	5.10

On February 28, 2015, the last reported sale price of the common stock on the New York Stock Exchange was $4.84 per share.

As of February 28, 2015, based upon information received from our transfer agent and brokers and nominees, there were approximately 57 holders of record of the Company’s common stock. This number does not include owners for whom common stock may be held in “street” names.

Dividends

The Company has not paid cash dividends and does not anticipate paying cash dividends on the common stock in the foreseeable future.

Performance Graph

The following graph compares the yearly percentage change in the Company’s cumulative total stockholder return on its common shares with the cumulative total return of the S&P 500 Index and the SPDR S&P Oil & Gas Exploration and Production Index. For this purpose, the yearly percentage change in the Company’s cumulative total stockholder return is calculated by dividing (a) the sum of the dividends paid during the “measurement period,” and the difference between the price for the Company’s shares at the end and the beginning of the measurement period, by (b) the price for the Company’s common shares at the beginning of the measurement period. "Measurement period" means the period beginning at the market close on the last trading day before the beginning of the Company's fifth preceding fiscal year, through and including the end of the Company's most recently completed fiscal year. The Corporation first became listed on the New York Stock Exchange on October 12, 2006.

	2009	2010	2011	2012	2013	2014
SPDR S&P Oil & Gas Exploration and Production	$100	$128	$130	$135	$171	$119
S&P 500 Composite	$100	$113	$113	$128	$166	$185
VAALCO Energy, Inc.	$100	$157	$133	$190	$151	$100

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2014 regarding the number of shares of common stock that may be issued under the Company's compensation plans. Please refer to Note 3 to the consolidated financial statements for additional information on stock based compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	2,837,251	$ 7.05	4,654,218
Equity compensation plans not approved by security holders	1,927,790	$ 7.94	3,334
Total	4,765,041	$ 7.41	4,657,552

Issuer Purchases of Equity Securities for Year Ended December 31, 2014

In the year ended December 31, 2014, the Company repurchased 231,142 shares at an average price of $8.08 per share totaling $1.9 million. The shares repurchased were related to the options exercised by employees, which are approved under the long term incentive plans as disclosed in our proxy filings. The Company did not repurchase any shares in the fourth quarter of 2014.

Item 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information about the Company. The financial information for each of the five years in the period ended December 31, 2014 has been derived from the Company's Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of the Company's future results.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands, except per share amounts)				
Total revenues	$127,691	$169,277	$195,287	$210,436	$134,472
Net income (loss)	$(77,550)	$43,072	$5,339	$40,562	$42,387
Net income (loss) attributable to VAALCO Energy, Inc.	$(77,550)	$43,072	$631	$34,145	$37,340
Basic net income (loss) per share attributable to VAALCO Energy, Inc. common shareholders	$(1.36)	$0.75	$0.01	$0.60	$0.66
Diluted net income (loss) per share attributable to VAALCO Energy, Inc. common shareholders	$(1.36)	$0.74	$0.01	$0.59	$0.65
Total assets	$248,849	$308,167	$267,956	$275,015	$238,400
Total debt	$15,000	$0	$0	$0	$0

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

INTRODUCTION

VAALCO owns producing properties and conducts exploration activities as an operator in Gabon, West Africa, conducts exploration activities as an operator in Angola, West Africa, and participates in exploration and development activities as a non-operator in Equatorial Guinea, West Africa and in the United States. VAALCO is the operator of unconventional resource properties in the United States in North Texas and a leasehold in Montana. The Company also owns minor interests in conventional production activities as a non-operator in the United States.

A significant component of the Company's results of operations is dependent upon the difference between prices received for its offshore Gabon oil production and the costs to find and produce such oil. Oil (and gas) prices have been and are expected in the future to be volatile and subject to fluctuations based on a number of factors beyond the control of the Company. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline, and current prices are significantly less than they have been over the last several years. Sustained low oil and gas prices could have a material adverse effect on the Company's financial condition, the carrying value of its proved reserves and the amount of its borrowing base under the Company's credit facility. Similarly, the costs to find and produce oil and gas are largely not within the control of the Company, particularly in regard to the cost of leasing drilling rigs to drill and maintain offshore wells.

A key focus of the Company is to maintain oil production from the Etame Marin block located offshore Gabon at optimal levels within the constraints of the existing infrastructure. The Company operates the Etame, Avouma/South

Tchibala field, Southeast Etame/North Tchibala, and Ebouri fields on behalf of a consortium of five companies. Three subsea wells plus production from two platforms are tied back by pipelines to deliver oil and associated gas through a riser system to allow for delivery, processing, storage and ultimately offloading the oil from a leased Floating, Production, Storage and Offloading vessel ("FPSO") anchored to the seabed on the block. In the third quarter of 2014, the Company finished installation of two additional platforms, one located in the Etame field and the other between the Southeast Etame/North Tchibala field. In the first quarter of 2015, one development well drilled from the Etame platform was brought onto production. With the FPSO limitations of approximately 25,000 BOPD and 30,000 barrels of total fluids per day, the challenge is to optimize production on both a near and long-term basis subject to investment and operational decisions by the Company and the consortium.

As part of the near-term optimization, a drilling and workover campaign began in 2012 with the arrival of a drilling rig to conduct a six well program that was ultimately increased to an eight well program extending into 2014. The 2014 program included the drilling of an exploration well, a replacement development well and one workover to replace electrical submersible pumps. The Company drilled the exploration well in the first quarter of 2014, an unsuccessful effort due to non-commercial quantities of hydrocarbons being found. Accordingly, the Company expensed $1.9 million of incurred dry hole costs in the fourth quarter of 2013, with the remainder of $11.7 million of the dry hole cost being expensed in the first quarter of 2014. Additionally, in the first quarter of 2014, the Company performed a workover to replace the ESP's on a well in the Avouma/South Tchibala field and in April 2014, the Company commenced drilling of a development well in the South Tchibala field to replace a well with damaged casing. The well was successfully brought on production in May 2014.

In addition, the construction of the two additional platforms that were approved by the Company and its partners in 2012, finished construction and were installed in the third quarter of 2014. The two production platforms are part of the development plans for the Etame Marin block. One platform is located in the Etame field and the second platform is located between the Southeast Etame/North Tchibala field. The total cost to build and install the platforms in 2014 was $351.0 million ($106.5 million net to the Company). The cost of the wells is not included in the platform costs. In the third quarter of 2014, the Company contracted with a drilling rig to begin drilling development wells from the Etame platform and the Southeast Etame/North Tchibala platform. The Company drilled a successful exploration well in the Southeast Etame area in 2010 which will be developed from the second platform. The Company spudded the first well, Etame 8-H, from the Etame platform in the fourth quarter of 2014 and the well was shut-in as it was determined to be producing H_2S during the initial testing process. The Company is planning to conduct an extended well test of the Etame 8-H well, to confirm and quantify the presence of H_2S which was detected during the initial 17 hour flow test. The well test is expected to occur in the first half of 2015. In December 2014, the Company spudded the Etame 10-H well which was drilled to the 1-V fault block, and the well was brought on production in the first quarter of 2015. The Etame 10-H well confirmed the presence of an undrained lower lobe of the Gamba reservoir in this fault block with no H_2S present. Additional development wells are expected to be drilled in 2015 from the two platforms.

In July 2012, the Company discovered the presence of hydrogen sulfide (“H_2S”) from two of the three producing wells in the Ebouri field. The wells were shut-in for safety and marketability reasons resulting in a decrease of approximately 2,000 BOPD or approximately 10% of the gross daily production from the Etame Marin block at that time. In addition, H_2S was first detected in January 2014 and later confirmed in July 2014 in the Etame 5-H well in the Etame field, and this well has also been shut-in. Analysis and options for re-establishing production from the impacted areas continued through the fourth quarter of 2014. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including a processing facility capable of removing H_2S, recompletion of the temporarily abandoned wells, and potentially, additional new wells. Considering the substantial recent fall in oil prices, the Company and its partners are focusing on more cost efficient options for a processing facility (e.g. chemical removal options, construction of a smaller facility on existing structures, or the use of surplus equipment and used structures). There can be no assurances that the processing facility will be completed by 2017, if at all, or that a more cost effective facility will cover all affected areas of the Ebouri and Etame fields. It is expected that the timing of the project startup will be known as early as the fourth quarter of 2015 with a goal of re-establishing production from the area impacted by H_2S as soon as practical. Should the Company and its partners evaluation result in no economic alternative, a decrease of as much as 2.4 million barrels of proved undeveloped reserves could result.

In January 2014, the Company executed a loan agreement with the International Finance Corporation (IFC) for a $65.0 million reserve based loan facility (“RBL”) secured by the assets of the Company’s Gabon subsidiary. In the third quarter of 2014, the Company borrowed $15.0 million under the credit facility and is due upon full maturity in January 2019, at which point it can be extended or converted to a term loan. Our borrowing base under the IFC credit facility is based upon our proved reserves and risk adjusted probable reserves and is re-determined semi-annually by the IFC. In addition, the borrowing base may be adjusted pursuant to certain non-scheduled re-determinations. However, the credit facility contains a covenant that prevents us from borrowing any amounts that would cause our debt to equity ratio to exceed 60:40. As of December 31, 2014, we estimate that this covenant would restrict our total borrowing capacity to approximately $25.0 million (of which $15.0 million has been borrowed as of December 31, 2014).

In the fourth quarter of 2014, the Company recorded an impairment loss of $98.3 million to write down its investment in certain fields comprising the Etame Marin Block, offshore Gabon to its fair value. An impairment of $38.5 million was recorded in the Etame field, $5.9 million in the Ebouri field and $53.9 million in the Southeast Etame/North Tchibala field. The impairment is a result of the recent decline in the forecasted oil prices used in the impairment testing and calculation.

Besides the offshore Etame Marin block in Gabon, the Company operates the Mutamba Iroru block located onshore Gabon. The Company has a 50% working interest in the block (41% net working interest assuming the Republic of Gabon exercises its back-in rights). After drilling two unsuccessful exploration wells on the block in 2009, the Company entered into an agreement with Total Gabon to continue the exploration activities. Following seismic reprocessing, a discovery well was drilled in 2012. A revised production sharing contract ("PSC") including exploration rights is in the approval process. The term sheet, which specifies financial and other obligations to be included in the PSC, was agreed to and signed by the Company, its joint venture partner, and the Government of Gabon on July 31, 2014. The form of the PSC has been completed and presented to the Company and its joint venture partner for execution. The joint venture partner has withheld its approval of the new PSC pending resolution of certain legal aspects of the new agreement with the Government of Gabon. In March 2015, the joint venture partner indicated to the Company that the legal aspects have not yet been resolved to their satisfaction. The Company can provide no assurance as to the joint venture partner approving the PSC. The Company remains committed to this block and further meetings of the parties are expected to occur in the first half of 2015. After the PSC is approved, an application for a development area will be made by the Company. After issuance of a development area, the next step is the submittal of the plan of development. The Company can provide no assurances as to the either the approval of the PSC by the Government of Gabon, or the subsequent approval of a development area by the Government of Gabon.

Development of the onshore block is expected to capitalize on synergies such as experienced personnel from our operating base office space, warehouse and open yard space in Port Gentil, Gabon.

The Company signed a production sharing contract in November 2006 for Block 5 offshore Angola, a 1.4 million acre property. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. The Company had a two well exploration commitment under the original production sharing contract.

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Additional extensions were subsequently granted by the Angolan government until November 30, 2014 to drill the two exploration commitment wells.

In the fourth quarter of 2013, the Company received a written confirmation from The Ministry of Petroleum of Angola that the available 40% working interest in Block 5, offshore Angola, has been assigned to Sonangol E.P., the National Concessionaire. The Ministry of Petroleum also confirmed that Sonangol E.P. would assign the aforementioned participating interest to its exploration and production affiliate, Sonangol P&P. The assignment was made effective on January 1, 2014. The unpaid amounts from the defaulted partner plus the amounts incurred during the period prior to assignment of the working interest to Sonangol P&P are believed by the Company to be the responsibility of the acquirer of the working interest. The Company invoiced Sonangol P&P for these amounts totaling $7.6 million plus interest in April 2014. Due to the uncertainty of collection, the Company has recorded a full allowance totaling $7.6 million as of December 31, 2014, during 2011 through 2013 for the amounts owed to the Company above its 40% working interest plus the 10% carried interest.

Late in 2013, the Company proceeded to obtain additional seismic data covering the deeper segment of the block. The seismic data was reprocessed during 2014 and will continue to be reprocessed in 2015. With the purchase of the additional seismic data, the Company has already satisfied the seismic obligation of the SEP.

A drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well began drilling in the first quarter of 2015. Drilling this well satisfies one of the four exploration well obligations and will release $5.0 million of the $20.0 million recorded as restricted cash at December 31, 2014 by the Company.

An important objective for the Company is growth by the establishment of meaningful production operations in more than one country. The Company routinely evaluates working interest opportunities primarily in the West African geographic area where the Company has significant expertise and where the base of the foreign operations is located. During 2012, the Company identified an opportunity to purchase a working interest in Block P, Equatorial Guinea. In November 2012, the Company completed the acquisition of a 31% working interest in the block at a cost of $10.0 million. Prior to the Company's acquisition, two oil discoveries had been made on the block, and there is exploration potential on other areas of the block. During 2014, the Company and GEPetrol continued to work on a joint operatorship model whereby the Company would have a significant role in operator activities on the block. Additionally, the Company has been working with the Ministry of Mines, Industry and Energy regarding timing and budgeting for development and exploration activities.

With a focus on diversification and utilizing available capital resources, the Company invested in three non-conventional acreage acquisitions in Texas and Montana in late 2010 and in 2011. Two wells have been drilled on the Texas acreage and brought on production. In Montana, four unsuccessful exploration wells were drilled on the two properties in 2012 and the fifth unsuccessful exploration well was drilled in the first quarter of 2013. With the unsuccessful results in Montana and due to the surplus of domestically produced light, sweet crude oil in the North America, and the associated current low price environment, the Company does not expect to focus on domestic property acquisitions or further development of domestic owned properties in its short-term business plans.

CRITICAL ACCOUNTING POLICIES

The following describes the critical accounting policies used by the Company in reporting its financial condition and results of operations. In some cases, accounting standards allow more than one alternative accounting method for reporting, such is the case with accounting for oil and gas activities described below. In those cases, the Company's reported results of operations would be different should it employ an alternative accounting method.

Successful Efforts Method of Accounting for Oil and Gas activities

The SEC prescribes, in Regulation S-X, the financial accounting and reporting standards for companies engaged in oil and gas producing activities. Two methods are prescribed: the successful efforts method and the full cost method. Like many other oil and gas companies, the Company has chosen to follow the successful efforts method. Management believes that this method is preferable, as the Company has focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by attachment to the drilling operations of the Company. Costs of successful wells, development dry holes and leases containing productive reserves are capitalized and amortized on a unit-of-production basis over the life of the related reserves. Other exploration costs, including geological dry exploration well, and geophysical expenses applicable to undeveloped leasehold, leasehold expiration costs and delay rentals are expensed as incurred.

In accordance with the successful efforts method of accounting, the Company reviews proved oil and gas properties for indications of impairment whenever events or circumstances indicate that the carrying value of its oil and gas properties may not be recoverable. When it is determined that an oil and gas property's estimated future net cash flows will not be sufficient to recover its carrying amount, an impairment charge must be recorded to reduce the carrying amount of the asset to its estimated fair value. This may occur if a field contains lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field.

Impairment of Unproved Property

The Company evaluates its unproved properties for impairment on a property by property basis. The majority of the Company's unproved property consists of acquisition costs related to its undeveloped acreage in Angola, Equatorial Guinea and Gabon. On at least a quarterly basis, management reviews the unproved property for indicators of impairment based on the Company's current exploration plans with consideration given to results of any drilling and seismic activity during the period and known information regarding exploration activity by other companies on adjacent blocks. See Item 2 – Properties and Note 6 to the consolidated financial statements for further information on the Company's exploration plans in Angola and Equatorial Guinea.

Asset Retirement Obligations ("ARO")

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore oil and gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with The Company's oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Net cash provided by operating activities for 2014 was $23.4 million, as compared to $75.4 million in 2013 and $94.0 million in 2012. The decrease of $52.0 million in net cash provided by operating activities is primarily attributable to a decrease in working capital components of approximately $25.1 million, a decrease in net income by $120.6 million offset by an increase in non-cash adjustments of $93.7 million. The increase in non-cash adjustments is primarily a result an impairment loss of $98.3 million to write down the investment in the Etame Marine Block, offshore Gabon to its fair value, an increase in depreciation, depletion and amortization of $3.2 million, and $1.6 million in leasehold for the Etame Marin Block due to the expiration of the exploration license offset by a decrease in dry hole costs of $9.2 million. The decrease of $18.6 million in net cash provided by operating activities in 2013 versus 2012 was primarily attributable to a decrease in working capital components of approximately $31.7 million and a decrease in non-cash adjustments to net income of $24.6 million. The decrease in non-cash adjustments was a result of a decrease in depreciation of $3.0 million, a decrease in dry hole costs of $14.8 million and a decrease in impairment of proved properties of $7.6 million. The decrease was partially offset by an increase in net income of $37.7 million.

Net cash used in investing activities in 2014 was $101.4 million, compared to net cash used in investing activities for 2013 of $67.9 million and net cash used in investing activities in 2012 of $71.8 million. In 2014, the Company paid $92.2 million for capital expenditures, and an additional $10.0 million in restricted cash was recorded, offset by the release of $0.8 million of restricted cash. In 2013, the Company paid $66.9 million for capital expenditures, and recorded $1.1 million in restricted cash. In 2012, the Company paid $71.9 million for capital expenditures, partly offset by a $0.1 million release of restricted cash.

In 2014, net cash provided in financing activities was $16.5 million consisting of $15.0 million of borrowings offset by $2.3 million of debt issuance cost related to the $65.0 million credit facility from the IFC. In addition, $5.7 million of proceeds from issuance of common stock upon exercise of options was offset by repurchase of treasury stock from options exercise of $1.9 million. In 2013, net cash used in financing activities was $7.7 million consisting of repurchase of treasury stock for $11.5 million partially offset by proceeds from issuance of common stock upon exercise of options of $3.7 million. In 2012, net cash used in financing activities was $28.5 million consisting of an acquisition of a noncontrolling interest for $26.2 million and distributions to a noncontrolling interest owner of $5.6 million, partially offset by proceeds from the issuance of common stock upon the exercise of options of $3.3 million.

In recent history, the Company's primary source of capital resources has been from cash flows from operations. On December 31, 2014, the Company had cash balances of $69.1 million and restricted cash of $22.4 million. The Company believes that these cash balances combined with cash flow from operations and available borrowings of $10.0 million from the credit facility will be sufficient to fund the Company's 2015 capital expenditure budget, which is expected to range from approximately $65.0 million to $75.0 million to further develop the Etame Marin block offshore Gabon and to drill well on Block 5 in Angola.

The Company invests cash not required for immediate operational and capital expenditure needs in short-term bankers acceptance and money market instruments primarily with JPMorgan Chase & Co. The Company does not invest in the asset-backed commercial paper. As operator of the Etame, Avouma/South Tchibala and Ebouri producing fields, and the Southeast Etame/North Tchibala field currently being developed, the Company enters into project related activities on behalf of its working interest partners. The Company generally obtains advances from its partners prior to significant funding commitments.

Capital Expenditures

In 2014, the Company invested $92.2 million in property and equipment additions primarily associated with the construction of the two new platforms and production facilities offshore Gabon. In 2014, the Company invested $60.8 million in platform costs, $13.2 million related to the drilling of two development wells in the Etame field, and $6.1 million related to the drilling of a replacement development well in South Tchibala field, offshore Gabon. In 2013, the Company invested $48.4 million in property and equipment additions (including amounts carried in accounts payable and excluding exploration dry hole costs), primarily associated with the construction of the two new platforms and production facilities offshore Gabon. In 2012, the Company invested $46.4 million in property and equipment additions (including amounts carried in accounts payable and excluding exploration dry hole costs), primarily associated with $13.6 million to drill and complete the second Granite Wash formation well in the United States and one exploratory well in Montana, $16.7 million for platform modifications and production facilities offshore Gabon, $10.0 million to acquire mineral interests in Block P offshore Equatorial Guinea, and $6.0 million to drill an exploratory well onshore Gabon.

Oil and Gas Exploration Costs

As described above, the Company uses the "successful efforts" method of accounting for its oil and gas exploration and development costs. All expenditures related to exploration, with the exception of costs of drilling exploration wells, are charged as an expense when incurred. The costs of exploration wells are capitalized pending determination of whether commercially producible oil and gas reserves have been discovered. If the determination is made that a well did not encounter potentially economic oil and gas quantities, the well costs are charged as an expense. Exploration expense in 2014 was $15.4 million, including $11.7 million in dry hole costs related to one unsuccessful exploration well and $1.6 million related to the impairment of leasehold costs offshore Gabon. Additionally, in 2014 the Company incurred exploration expenditures of $1.7 million in Angola related to the reprocessing of seismic data covering the deeper segment of the block. Exploration expense in 2013 was $23.9 million, including $11.4 million in dry hole costs related to one unsuccessful exploration well and impairment of leasehold costs in the United States. In 2013, the Company also incurred dry hole costs of $11.3 million related to three dry holes in Gabon. Additionally, in 2013 the Company incurred exploration expenditures of $1.2 million internationally for various geological and geophysical activities. Exploration expense in 2012 was $41.0 million, including a $37.3 million in dry hole costs related to five unsuccessful exploration wells in the United States, and $0.9 million spent for various geological and leasehold related activities in the United States. Additionally, in 2012 the Company incurred exploration expenditures of $2.8 million internationally for various geological and geophysical activities.

Contractual Obligations

The table below summarizes the Company’s net share of obligations and commitments at December 31, 2014:

Payment Period

(in thousands $)	2015	2016	2017	2018	2019	Thereafter	Total
Long Term Debt (1)	$-	$-	$-	$-	$15,000	$ -	$15,000
Operating leases (2)	$44,067	$17,848	$7,696	$7,663	$7,663	$ 7,615	$92,552

(1) The facility extends through December 2019 at which point it can be extended or converted to a term loan at the Company’s option.
(2) The Company is guarantor of a lease for the FPSO utilized in Gabon, which has remaining obligations of $155.0 million. The Company’s share of these payments is included in the table above. Approximately 72% of the payment is co-guaranteed by the Company’s partners in Gabon. In addition to the FPSO amounts, the schedule includes the Company’s share of its other lease obligations. The Company’s shares of rig commitments are included in this information.

The Company contracted with drilling rigs in the year ended December 31, 2014. In the third quarter of 2014, the Company contracted with a drilling rig to begin a multi-well development drilling campaign offshore Gabon. The campaign includes drilling of wells from the Etame platform and wells from the Southeast Etame/North Tchibala platform. The drilling rig commenced in October 2014 and provides a commitment until July 2016, at a day rate of approximately $168,000. The total commitment related to this rig is $25.8 million. The second drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well began drilling in the first quarter of 2015. The drilling rig provides a forty- five day commitment at a day rate of approximately $338,000. The total commitment related to this rig is $7.6 million. Such rates are subject to standard reimbursement and escalation contractual provisions.

As part of securing the first of two five-year extension in 2011 to the Etame field production license to which the Company is entitled from the government of Gabon, the Company agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin Block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over the remaining life of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The initial funding took place in October 2014 for calendar years 2012 and 2013 totaling $8.4 million ($2.3 million net to the Company). The funding for calendar year 2014 was paid in the first quarter of 2015 in the amount of $4.2 million ($1.2 million net to the Company). As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company’s balance sheet. The cash funding is reflected under other long term assets as “Abandonment Funding”.

Additionally, in October 2014, the Company received a provisional audit report related to the Etame Marin block operations from the Gabon Taxation Department as part of a special industry-wide audit of business practices and financial transactions in the Republic of Gabon. The Company currently cannot reasonably estimate a range of potential loss, if any, as a result of the audits. While the ultimate outcome of the claim and impact on VAALCO cannot be predicted, management believes that the claims are unfounded. In November 2014, we responded to the Gabon Taxation Department requesting joint meetings to advance the resolution of this matter and provided a formal reply to the provisional audit report in February 2015.

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awarded the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract, the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Additional extensions were subsequently granted by the Angolan government until November 30, 2014 to drill the two exploration commitment wells. In the fourth quarter of 2013, the Company received written confirmation from The Ministry of Petroleum of Angola that the available 40% working interest in Block 5, offshore Angola, has been assigned to Sonangol E.P., the National Concessionaire. The Ministry of Petroleum also confirmed that Sonangol E.P. would assign the aforementioned participating interest to its exploration and production affiliate, Sonangol P&P.

In April 2014, the Company received a letter and contractual amendment proposal from Sonangol E.P., the national oil company in Angola related to the extension of the two well drilling commitment. Due to the uncertainty that the primary term of the exploration license would be extended by the Republic of Angola in accordance with the contractual amendment proposal before the November 30, 2014 expiration date, in October 2014, the Company entered into the Subsequent Exploration Phase (“SEP”), together with its working interest partner, Sonangol P&P. The SEP option was provided for in the Production Sharing Agreement signed in 2006 with the Republic of Angola. The SEP extends the exploration period for an additional three year period such that the new expiry date for exploration activities is November 30, 2017. Entering the SEP requires the Company and its partner to acquire 3D seismic covering six hundred square kilometers and to drill two additional exploration wells. The Company has already satisfied the seismic obligation of the SEP with the purchase of 3D seismic in the outboard segment of the block in late 2013, which is currently being processed and will continue to be processed into 2015.

Late in 2013, the Company proceeded to obtain additional seismic data covering the deeper segment of the block. The seismic data was reprocessed during 2014 and will continue to be reprocessed in 2015. With the purchase of the additional seismic data, the Company has already satisfied the seismic obligation of the SEP.

By entering into the SEP, the Company is required to drill a total of four exploration wells during the exploration extension period. The four well obligations include the two well commitments under the primary exploration period that carries over to the SEP period. A $10.0 million dollar assessment ($5.0 million dollars net to VAALCO) applies to each of the four commitment exploration wells, if any, that remain undrilled at the end of the exploration period in November 2017. Restricted cash of $10.0 million for the two new commitment wells was recorded in the fourth quarter of 2014. At December 31, 2014 the Company had $20.0 million in restricted cash related to the offshore Angola exploration agreement.

A drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well began drilling in the first quarter of 2015. Drilling this well will satisfy one of the four exploration well obligations and will release $5.0 million of the $20.0 million recorded as restricted cash at December 31, 2014 by the Company.

The Company is carrying $14.8 million of asset retirement obligations as of December 31, 2014, representing the present value of these obligations as of that date.

RESULTS OF OPERATIONS

Year Ended December 31, 2014 Compared to Years Ended December 31, 2013 and 2012

Total Revenues

Total oil and gas sales for 2014 were $127.7 million as compared to $169.3 million and $195.3 million for 2013 and 2012, respectively. The decrease in revenue is primarily related to the lower number of barrels lifted from the Company’s offshore Gabon operations and a decrease in the average realized sales price per barrel in the year ended December 31, 2014 compared to the year ended December 31, 2013.

Oil Revenues

Gabon

Crude oil revenues for 2014 were $126.3 million, as compared to revenues of $167.4 million and $192.5 million for 2013 and 2012 respectively. In 2014, the Company sold approximately 1,350,000 net barrels of oil at an average price of $93.68 per Bbl. In 2013, the Company sold approximately 1,544,000 net barrels of oil at an average price of $108.42 per Bbl. In 2012, the Company sold approximately 1,730,000 net barrels of oil at an average price of $111.24 per Bbl. The decrease in revenue is primarily related to the lower number of barrels lifted and a decrease in the average realized sales price per barrel in the year ended December 31, 2014 compared to the year ended December 31, 2013.

In the year ended December 31, 2014, the Company produced approximately 1,417,000 barrels, compared to approximately 1,525,000 barrels for the same period ended December 31, 2013. The decrease in production was primarily due to a six day shut-in of the FPSO for scheduled maintenance and system upgrades and temporary well shut-ins for maintenance and repairs. In 2012, the Company produced 1,721,000 barrels. Crude oil sales are a function of the number and size of crude oil liftings in each quarter from the FPSO and thus crude oil sales do not always coincide with volumes produced in any given quarter.

United States

Condensate sales from the Granite Wash formation wells, located in Hemphill County, Texas for the year 2014 were $0.3 million, resulting from the sale of approximately 3,000 net barrels of condensate at an average price of $85.89 per Bbl. Condensate sales from the Granite Wash formation wells, located in Hemphill County, Texas for the year 2013 were $0.4 million, resulting from the sale of approximately 5,000 net barrels of condensate at an average price of $85.67 per Bbl. Condensate sales from the Granite Wash formation wells, located in Hemphill County, Texas for the year 2012 were $0.8 million, resulting from the sale of approximately 10,000 net barrels of condensate at an average price of $81.68 per Bbl.

Natural Gas Revenues

United States

Natural gas revenues including revenues from natural gas liquids for the year 2014 were $1.0 million, resulting from the sale of approximately 200 MMcf at an average price of $4.60 per Mcf, compared to $1.5 million and $1.9 million for the years 2013 and 2012 respectively. In 2013, natural gas sales were approximately 300 MMcf at an average price of $4.50 per Mcf. In 2012, natural gas sales were approximately 500 MMcf at an average price of $3.66 per Mcf.

Operating Costs and Expenses

Production expense for 2014 was $31.7 million as compared to $36.6 million and $26.7 million for 2013 and 2012, respectively. The decrease in production expense in year ended December 31, 2014 compared to 2013 was due to lower well workover costs to replace electrical submersible pumps. In 2014, the Company spent $2.1 million for workover to replace electrical submersible pumps, compared to the $7.6 million in 2013 to replace electrical submersible pumps on three wells offshore Gabon. Production expense in 2013 was higher than 2012 due to well workover costs to replace electrical submersible pumps in three offshore Gabon wells for $7.6 million and $2.1 million for generator repairs on the Avouma platform.

Exploration expense in 2014 was $15.4 million, including $11.7 million in dry hole costs related to one unsuccessful exploration well and $1.6 million related to the impairment of leasehold costs offshore Gabon. Additionally, in 2014 the Company incurred exploration expenditures of $1.7 million in Angola related to the reprocessing of seismic data covering the deeper segment of the block. Exploration expense in 2013 was $23.9 million, of which $11.4 million was incurred in the United States related to the two unsuccessful exploration wells and impairment of leasehold costs. The Company incurred dry hole costs of $9.4 million related to two offshore Gabon unsuccessful exploration wells during the first three quarters of 2013. In the fourth quarter of 2013, the Company expensed $1.9 million in dry hole cost for an additional offshore Gabon exploration well due to non-commercial quantities of hydrocarbons being found. The remainder of the dry hole costs associated with this well was expensed in the first quarter of 2014. Additionally, in 2013 the Company incurred exploration expenditures of $1.2 million internationally for various geological and geophysical activities. Exploration expense in 2012 was $41.0 million, including a $37.3 million in dry hole costs related to five unsuccessful exploration wells in the United States, and $0.9 million spent for various geological and leasehold related activities in the United States. Additionally, in 2012 the Company incurred exploration expenditures of $2.8 million internationally for various geological and geophysical activities.

Depreciation, depletion and amortization expense was $20.1 million in 2014 as compared to $16.9 million and $19.9 million for 2013 and 2012, respectively. Depletion, depreciation and amortization expense increased in 2014 compared to 2013 was due to higher depletion rates. Depletion, depreciation and amortization expense decreased in 2013 compared to 2012 primarily due to lower sales volumes. The 2014 depletion rates for the Ebouri field averaged $38.46 per Bbl, Avouma/South Tchibala field averaged $16.51 per Bbl, and the Etame field averaged $1.90 per Bbl. Depletion rates for the Granite Wash formation wells averaged $3.71 per Mcf. The 2013 depletion rates for the Ebouri field averaged $27.76 per Bbl, Avouma/South Tchibala field averaged $13.90 per Bbl, and the Etame field averaged $1.81 per Bbl. Depletion rates for the Granite Wash formation wells averaged $3.87 per Mcf. The 2012 depletion rates for the Ebouri field averaged $21.14 per Bbl, Avouma/South Tchibala field averaged $4.11 per Bbl, and the Etame field averaged $4.64 per Bbl. Depletion rates for the Granite Wash wells in 2012 averaged $6.16 per Mcf.

General and administrative expense for 2014 was $14.2 million as compared to $11.3 million and $11.8 million for 2013 and 2012, respectively. The increase in 2014 was primarily due to increased personnel, and higher support services costs. The decrease in general and administrative expense in 2013 versus 2012 was primarily due to lower overhead reimbursements from Gabon.

During 2014, the Company incurred $3.3 million of non-cash stock based compensation expense, as compared to $3.0 million and $2.4 million for 2013 and 2012, respectively.

During 2014, the Company recorded bad debt allowance of $2.4 million related to past due reimbursements of Value Added Tax (“VAT”) from the government of Gabon. The allowance pertains to amounts owing in excess of twelve months. In 2013 and 2012, the Company recorded bad debt and other expenses of $3.3 million and $1.6 million, respectively, related to the uncertainty in collecting its partner receivable in Angola. The Company invoiced $7.6 million to its new partner, Sonangol P&P, for the cumulative accounts receivable amount in the first quarter of 2014 and is still working towards the recovery of the amount. In the fourth quarter of 2013, the Company also recorded other expense in the amount of $1.8 million for the Company's share of the settlement of a cost account audit performed by the Republic of Gabon for the 2009 and 2010 calendar years.

During 2014, the Company recorded an impairment loss of $98.3 million to write down its investment in certain fields comprising the Etame Marin Block, offshore Gabon to its fair value. An impairment of $38.5 million was recorded in the Etame field, $5.9 million in the Ebouri field and $53.9 million in the Southeast Etame/North Tchibala field. The impairment is a result of the recent decline in the forecasted oil prices used in the impairment testing and calculation. In 2013, the Company recorded no impairment losses. In 2012, the Company recorded impairment losses of $7.6 million, respectively, on its proved property, to write down its investment in the Granite Wash formation of North Texas to its fair value.

Operating Income (loss)

Operating loss for 2014 was $54.4 million as compared to net income of $77.2 million and $86.6 million for 2013 and 2012, respectively. The operating loss in 2014 is primarily due to impairment loss of $98.3 million in the Etame Marin Block offshore Gabon and due to lower revenues related to lower sales volumes, and a decrease in the realized sales price per barrel of oil. The lower operating income for 2013 compared to 2012 is primarily attributable to lower revenues due to lower sales volumes, and an increase in production expense partially offset by a decrease in exploration expense as discussed above.

Other Income (Expense)

Interest income was $0.1 million for each of the years 2014, 2013 and 2012. All 2014, 2013 and 2012 amounts represent interest earned and accrued on cash balances and restricted cash.

During 2014, other expense was $0.7 million as compared to other expense of $0.1 million in 2013 and other income of $0.4 million for 2012. Other income and expense is primarily the result of foreign currency transaction gains and losses from the Company's foreign operations.

Income Taxes

In 2014, the Company incurred $22.5 million in income tax expense as compared to $34.1 million and $81.8 million for 2013 and 2012, respectively. All income tax expenses were associated with the Etame Marin block production, and were incurred in Gabon. The lower income tax expense for 2014 compared to 2013 was primarily the result of lower revenue due to lower sales volumes, resulting in lower profit oil barrels subject to taxes, a significant increase in costs incurred due to the construction of two new platforms and cost incurred associated with active rigs under contract for the majority of 2014 in the Etame Marin block. The lower income tax expense for 2013 compared to 2012 was primarily the result of lower revenue due to lower sales volumes, resulting in lower profit oil barrels subject to taxes, a significant increase in costs incurred due to the construction of two new platforms and cost incurred associated with an active rig under contract for the majority of 2013 in the Etame Marin block.

Net Income (loss)

Net loss for 2014 was $77.6 million compared to net income of $43.1 million and net income of $5.3 million for 2013 and 2012, respectively. The net loss in 2014 is primarily due to an impairment loss of $98.3 million in the Etame Marin Block offshore Gabon and due to lower revenues related to lower sales volumes, and a decrease in the realized sales price per barrel of oil. The increase in net income in 2013 compared to 2012 is due to lower exploration costs, lower income tax expenses and no impairment of proved properties.

The noncontrolling interest, which was associated with VAALCO Energy (International), Inc., a subsidiary that was 90.01% owned by the Company, was acquired by the Company at a cost of $26.2 million effective October 1, 2012. Income attributable to the noncontrolling interest in the Gabon subsidiary was $4.7 million for 2012 prior to acquisition.

OFF BALANCE SHEET ARRANGEMENTS

For a discussion of off balance sheet arrangements associated with the guarantee by the Company of the charter payments for the FPSO located in Gabon, see Note 6 to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk
Market Risk

The Company's major market risk exposure continues to be the prices applicable to its oil and gas production. Sales prices are primarily driven by the prevailing market price. Historically, prices received for oil and gas production have been volatile and unpredictable.

Foreign Exchange Risk

Our results of operations and financial condition are affected by currency exchange rates. While oil sales are denominated in U.S. dollars, portions of our operating costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing operating costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in response to international political conditions, general economic conditions and other factors beyond our control.

Interest Rate Risk

Our floating rate credit facility exposes us to risks associated with changes in interest rates and as such, future earnings are subject to change due to changes in this interest rate. At December 31, 2014, the Company has borrowed $15.0 million under the credit facility. Fluctuations in floating interest rates will cause the Company's annual interest costs to fluctuate. During the fourth quarter of 2014, the interest rate on the Company's bank debt averaged 4.32%. If the balance of the bank debt at December 31, 2014 were to remain constant, a 1% change in market interest rates would impact our cash flow by an estimated $37,500 per quarter.

Commodity Price Risk

The Company had no derivatives in place as of the date of this report, or throughout 2014, 2013 or 2012.

Item 8. Financial Statements and Supplementary Data
The information required here is included in the report as set forth in the "Index to Consolidated Financial Information" on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None.

Item 9A. Controls and Procedures
Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by the Company in the reports it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the

Company's management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. The Company's management, including the Company's principal executive officer and principal financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below, material weaknesses were identified in our internal control over financial reporting. As a result of the material weaknesses, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were not effective at December 31, 2014. Notwithstanding the identified material weaknesses, management believes the consolidated financial statements included in this Annual Report on Form 10-K fairly represent in all material respects our financial condition, results of operations and cash flows at and for the periods presented in accordance with U.S. GAAP.

Management's Annual Report on Internal Control Over Financial Reporting

The Company's management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of the Company's management, including the Company's principal executive and principal financial officers, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework").

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

Based on our evaluation under the COSO Framework, our management concluded that our internal control over financial reporting was not effective as of December 31, 2014 as a result of the identification of material weaknesses described below.

Internal control over the preparation and review of the impairment evaluation of oil and gas properties - We did not maintain effective internal controls over the preparation and review of the impairment evaluation of oil and gas properties. Specifically, we did not effectively operate controls over management's review of the impairment assessment, including its review of certain cost elements to be included in the calculation and its review of the independent third party reserves report used in the calculation. This material weakness resulted in errors that, if not corrected, would have resulted in a material misstatement of the amount of our impairment of oil and gas properties.

Control environment, risk assessment and internal controls over financial reporting due to insufficient financial reporting resources - We did not maintain an effective control environment and did not perform an effective risk assessment based on the criteria established in the COSO Framework. As a result, we did not maintain effective internal control over financial reporting due to the failure to maintain a sufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. We did not identify that the change in the complement of corporate accounting and finance personnel resulted in elevated risk that impacted our system of internal control, which in aggregate resulted in material weaknesses. Controls were not operating effectively over the review and preparation of the financial statements. This material weakness resulted in adjustments prior to the issuance of the financial statements that, if not corrected, would have resulted in a material misstatement of 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.

Deloitte & Touche LLP, the independent registered public accounting firm, has issued their report on the Company's internal control over financial reporting as of December 31, 2014, which is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control Over Financial Reporting

There were changes in our internal control over financial reporting due to the material weakness as described above that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's plan for remediation of our material weaknesses. In response to the identified material weaknesses, our management, with oversight from our Audit Committee, is taking the following actions to remediate the material weaknesses described above:

- Redesign controls over management's review of the evaluation of impairment testing of oil and gas properties to address the associated risks;
- Further expand documentation of the procedures for reviewing data used as inputs into the oil and gas properties impairment calculation;
- Hire an experienced corporate controller to fill a vacancy created during the fourth quarter of 2014 and hire additional resources as needed to supplement the existing corporate accounting and/or financial reporting team; and
- In response to recent significant turnover, enhance the business understanding and relevant knowledge possessed by those responsible for ensuring proper management review and effective financial reporting controls.

Management is committed to improving the Company's internal control processes and has developed a plan and timetable for the implementation of the remediation measures described above and will meet frequently with the Audit Committee to monitor the status of remediation activities. Management believes that the measures described above should remediate the material weaknesses identified and strengthen the Company's internal control over financial reporting. As the Company continues to evaluate and improve its internal control over financial reporting, additional measures to remediate the material weaknesses or modifications to certain of the remediation procedures described above may be necessary. The Company expects to complete the required remedial actions during fiscal year 2015. While senior management and our audit committee are closely monitoring the implementation of these remediation plans, the Company cannot provide any assurance that these remediation efforts will be successful or that its internal control over financial reporting will be effective as a result of these efforts. Until the remediation steps set forth above are fully implemented and operating for a sufficient period of time, the material weaknesses described above will continue to exist.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of VAALCO Energy, Inc. and subsidiaries:

We have audited the internal control over financial reporting of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's 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 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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

- Internal controls over the preparation and review of the evaluation of indicators of impairment of oil and gas properties were not operating effectively;
- Internal controls over financial reporting were not operating effectively due to insufficient financial reporting resources; and
- An effective control environment was not maintained and an effective risk assessment was not performed.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014, of VAALCO Energy, Inc. and this report does not affect our report on such financial statements and financial statement schedule.

In our opinion, because of the effect of the material weaknesses identified above on the achievement of the objectives of the control criteria, the Company has not maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014 of the Company, and our report dated March 16, 2015 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

March 16, 2015

Item 9B. Other Information

The Company has disclosed all information required to be disclosed in a current report on Form 8-K during the year ended December 31, 2014 in previously filed reports on Form 8-K.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the Company's proxy statement for its 2015 annual meeting, which will be filed with the Commission within 120 days of December 31, 2014, and which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the Company's proxy statement for its 2015 annual meeting, which will be filed with the Commission within 120 days of December 31, 2014, and which is incorporated herein by reference.

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

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in the Company's proxy statement for its 2015 annual meeting, which will be filed with the Commission within 120 days of December 31, 2014, and which is incorporated herein by reference. Please see "Item 5 - Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities" for information on securities that may be issued under the Company's stock incentive plans.

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

Information required by this item will be included in the Company's proxy statement for its 2015 annual meeting, which will be filed with the Commission within 120 days of December 31, 2014, and which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference from the Company's definitive proxy statement for its 2015 annual meeting, which will be filed with the Commission within 120 days of December 31, 2014, and which is incorporated herein by reference.

54

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. The following is an index to the financial statements that are filed as part of this Form 10-K.

VAALCO ENERGY, INC. AND SUBSIDIARIES

(a) 2. Schedules are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.

(a) 3. Exhibits:

3.1 Certificate of Incorporation as amended through May 7, 2014 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014, and incorporated herein by reference).

3.2 Amended and Restated Bylaws (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on September 23, 2013, and incorporated herein by reference).

4.1 Form of Senior Debt Indenture (filed as Exhibit 4.1 to the Company’s Registration Statement on Form S-3 filed on May 13, 2014, and incorporated herein by reference).

4.2

	Form of Subordinated Debt Indenture (filed as Exhibit 4.2 to the Company’s Registration Statement on Form S-3 filed on May 13, 2014, and incorporated herein by reference).
10.1	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as an exhibit to the Company’s Form 10-QSB for the quarterly period ended September 30, 1995, and incorporated by herein by reference).
10.2(a)	Addendum No. 1 to Exploration and Production Sharing Contract, dated July 7, 2001, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
10.3(a)	Addendum No. 2 to Exploration and Production Sharing Contract, dated July 7, 2006, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
10.4(a)	Addendum No. 3 to Exploration and Production Sharing Contract, dated November 26, 2009, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.

10.5(a)	Addendum No. 4 to Exploration and Production Sharing Contract, dated January 5, 2012, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
10.6	Trustee and Paying Agent Agreement, dated June 26, 2002, by and among VAALCO Gabon (Etame), Inc., J.P. Morgan Trustee and Depositary Company Limited and JPMorgan Chase Bank, London Branch (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-QSB filed on August 19, 2002, and incorporated herein by reference).
10.7	Exploration and Production Sharing contract between the Republic of Gabon and VAALCO Production (Gabon), Inc., Permit Mutamba Iroru, dated November 11, 2005 (filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K filed on March 8, 2006, and incorporated herein by reference.).
10.8(a)	Production Sharing Agreement, dated November 1, 2006, between Sonangol, E.P. and VAALCO Angola (Kwanza), Inc.
10.9	Loan Agreement, dated January 30, 2014, between VAALCO Gabon (Etame), Inc. and International Finance Corporate (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 4, 2014, and incorporated herein by reference).
10.10*	Indemnity Agreement entered into among the Company and certain of its officers and directors listed therein (filed as an exhibit to the Company's Form 10 (File No. 0-20928) filed on December 3, 1992, as amended by Amendment No. 1, filed as an exhibit to the Company's Form 8 on January 7, 1993, and Amendment No. 2 filed as an exhibit to the Company's Form 8 filed on January 25, 1993, and hereby incorporated by reference herein).
10.11*	VAALCO Energy, Inc. 2001 Stock Incentive Plan (filed as Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed on August 17, 2001, and incorporated herein by reference).
10.12(a)*	Form of Award Agreement under the VAALCO Energy, Inc. 2001 Stock Incentive Plan
10.13*	VAALCO Energy, Inc. 2003 Stock Incentive Plan (filed as Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed on April 14, 2004, and incorporated herein by reference).
10.14(a)*	Form of Award Agreement under the VAALCO Energy, Inc. 2003 Stock Incentive Plan
10.15*	VAALCO Energy, Inc. 2007 Stock Incentive Plan (filed as Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed on July 25, 2007, and incorporated herein by reference).
10.16(a)*	Form of Nonstatutory Stock Option Agreement under the VAALCO Energy, Inc. 2007 Stock Incentive Plan
10.17*	VAALCO Energy, Inc. 2012 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 30, 2012, and incorporated herein by reference).
10.18(a)*	Form of Nonstatutory Stock Option Agreement under the VAALCO Energy, Inc. 2012 Long Term Incentive Plan
10.19*	VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 17, 2014, and incorporated herein by reference).
10.20(a)*	Form of Restricted Stock Award Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan.
10.21(a)*	Form of Nonstatutory Stock Option Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan
10.22(a)*	Form of Restricted Stock Award Agreement (for Directors) under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan.
10.23*	Executive Employment Agreement dated effective October 21, 2013, between VAALCO Energy, Inc. and Steven Guidry (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 23, 2013, and incorporated herein by reference).

10.24*	Severance and Consulting Agreement, dated June 4, 2014, between the Company and Robert L. Gerry III (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 6, 2014, and incorporated herein by reference).
21.1(a)	List of subsidiaries of the Company
23.1(a)	Consent of Deloitte & Touche LLP
23.2(a)	Consent of Netherland, Sewell & Associates, Inc. —Independent Petroleum Engineers
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (Domestic Properties)
99.2(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties)
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Label Linkbase Document.
101.PRE(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith
(b) Furnished herewith
* Management contract or compensatory plan or arrangement

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VAALCO ENERGY, INC.
(Registrant)

By /s/ GREGORY R. HULLINGER
Gregory R. Hullinger
Chief Financial Officer
Dated March 16, 2015

In accordance with the Exchange Act, this report has been signed below on the 16th day of March, 2015, by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
By: /s/ STEVEN P. GUIDRY Steven P. Guidry	Chairman of the Board and Chief Executive Officer (Principal Executive Officer) and Director
By: /s/ W. RUSSELL SCHEIRMAN W. Russell Scheirman	President, Chief Operating Officer and Director
By: /s/ GREGORY R. HULLINGER Gregory R. Hullinger	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
By: /s/ JAMES B. JENNINGS James B. Jennings	Lead Director
By: /s/ O. DONALD CHAPOTON O. Donald Chapoton	Director

By: /s/ ANDREW L. FAWTHROP Andrew L. Fawthrop	Director
By: /s/ JOHN J. MYERS, JR. John J. Myers, Jr.	Director
By: /s/ FREDERICK W. BRAZELTON Frederick W. Brazelton	Director

58

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of VAALCO Energy, Inc. and subsidiaries:

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related statements of consolidated operations, equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also include the financial statement schedule listed in the index at item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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, such consolidated financial statements present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidation financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 16, 2015 expressed an adverse opinion on the Company's internal control over financial reporting because of material weaknesses.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

March 16, 2015

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands of dollars, except number of shares and par value amounts)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 69,051	$ 130,529
Restricted cash	1,584	12,366
Receivables:		
Trade	19,527	16,972
Accounts with partners, net of allowance $7.6 million in 2014 and 2013	10,903	307
Other, net of allowance of $2.4 million in 2014, and zero in 2013	3,285	4,435
Crude oil inventory	1,905	352
Materials and supplies	286	164
Prepayments and other	6,509	2,339
Total current assets	113,050	167,464
Property and equipment - successful efforts method:		
Wells, platforms and other production facilities	338,641	215,701
Undeveloped acreage	22,133	23,705
Work in progress	25,157	64,489
Equipment and other	11,907	6,831
	397,838	310,726
Accumulated depreciation, depletion and amortization	(289,714)	(172,202)
Net property and equipment	108,124	138,524
Other assets:		
Restricted cash	20,830	830
Deferred tax asset	1,349	1,349
Deferred finance charge	1,959	-
Abandonment funding	3,537	-
Total Assets	$ 248,849	$ 308,167
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	38,540	42,561
Accounts with partners	-	3,268
Total current liabilities	$ 38,540	$ 45,829
Asset retirement obligations	14,846	11,464
Long term debt	15,000	-
Total liabilities	68,386	57,293
Commitments and contingencies (Note 6)		
VAALCO Energy Inc. shareholders' equity:		
Common stock, $0.10 par value, 100,000,000 authorized shares, 65,194,828 and	6,519	6,408

64,012,914 shares issued with 7,393,714 and 7,162,573 shares in treasury at Dec. 31, 2014 and 2013, respectively		
Additional paid-in capital	64,351	55,455
Retained earnings	146,892	224,442
Less treasury stock, at cost	(37,299)	(35,431)
Total Equity	180,463	250,874
Total Liabililities and Equity	$ 248,849	$ 308,167

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED OPERATIONS

(in thousands of dollars, except per share amounts)

	Year Ended December 31,		
	2014	2013	2012
Revenues:			
Oil and gas sales	$127,691	$169,277	$195,287
Operating costs and expenses:			
Production expense	31,718	36,615	26,724
Exploration expense	15,358	23,928	41,037
Depreciation, depletion and amortization	20,086	16,929	19,913
General and administrative expense	14,194	11,254	11,779
Bad debt and other expenses	2,400	3,326	1,621
Impairment of proved properties	98,341	-	7,620
Total operating costs and expenses	182,097	92,052	108,694
Operating income (loss)	(54,406)	77,225	86,593
Other income (expense):			
Interest income	75	73	145
Other, net	(733)	(111)	414
Total other income (expense)	(658)	(38)	559
Income (loss) before income taxes	(55,064)	77,187	87,152
Income tax expense	22,486	34,115	81,813
Net income (loss)	(77,550)	43,072	5,339
Less net income attributable to noncontrolling interest	-	-	(4,708)
Net income (loss) attributable to VAALCO Energy, Inc.	$(77,550)	$43,072	$631
Basic net income (loss) per share atributable to VAALCO Energy, Inc. common shareholders	$(1.36)	$0.75	$0.01
Diluted net income (loss) per share attributable to VAALCO Energy, Inc. common shareholders	$(1.36)	$0.74	$0.01
Basic weighted average shares outstanding	57,229	57,299	57,673
Diluted weighted average shares outstanding	57,229	57,925	58,832

See notes to consolidated financial statements

VAALCO ENERGY, INC AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED EQUITY

(in thousands of dollars)

	VAALCO ENERGY, Inc. Shareholders					
	Common Stock	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Noncontrolling Interest	Total
Balance at January 1, 2012	$6,238	$66,122	$180,739	$(23,975)	$ 3,943	$233,067
Stock issuance	76	3,432	-	-	-	3,508
Stock based compensation	-	2,406	-	-	-	2,406
Net income	-	-	-	-	-	-
Net income (loss)	-	-	631	-	4,708	5,339
Distribution to noncontrolling interest	-	-	-	-	(5,595)	(5,595)
Acquisition of noncontrolling interest	-	(23,144)	-	-	(3,056)	(26,200)
Balance at December 31, 2012	$6,314	$48,816	$181,370	$(23,975)	$ -	$212,525
Stock issuance	94	3,634	-	-	-	3,728
Stock based compensation	-	3,005	-	-	-	3,005
Treasury stock purchase	-	-	-	(11,456)	-	(11,456)
Net income	-	-	43,072	-	-	43,072
Balance at December 31, 2013	$6,408	$55,455	$224,442	$(35,431)	$ -	$250,874
Stock issuance	111	5,574	-	-	-	5,685
Stock based compensation	-	3,322	-	-	-	3,322
Treasury stock purchase	-	-	-	(1,868)	-	(1,868)
Net loss	-	-	(77,550)	-	-	(77,550)
Balance at December 31, 2014	$6,519	$64,351	$146,892	$(37,299)	$ -	$180,463

See notes to consolidated financial statements

VAALCO ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

(in thousands of dollars)

	Year Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$(77,550)	$43,072	$5,339
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	20,086	16,929	19,913
Amortization of debt issuance cost	328	-	-
Unrealized foreign exchange (gain) loss	(59)	22	(245)
Dry hole costs and impairment loss on unproved leasehold	13,273	22,490	37,289
Stock based compensation	3,322	3,005	2,406
Bad debt provision	2,400	1,562	1,621
Impairment loss	98,341	-	7,620
Change in operating assets and liabilities:			
Trade receivables	(2,555)	(9,011)	2,126
Accounts with partners	(13,864)	(12,649)	18,988
Other receivables	(1,250)	(53)	(199)
Crude oil inventory	(1,748)	279	(71)
Materials and supplies	(122)	173	(102)
Other long term assets	(3,537)	-	-
Prepayments and other	(4,172)	594	(766)
Accounts payable and other liabilities	(9,503)	8,988	39
Net cash provided by operating activities	23,390	75,401	93,958
CASH FLOWS FROM INVESTING ACTIVITIES			
Decrease/(increase) in restricted cash	(9,219)	(1,065)	78
Property and equipment expenditures	(92,179)	(66,879)	(71,915)
Net cash used in investing activities	(101,398)	(67,944)	(71,837)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of common stock	5,685	3,729	3,335
Debt issuance costs	(2,287)	-	-
Borrowings	15,000	-	-
Purchase of treasury stock	(1,868)	(11,456)	-
Distribution to noncontrolling interest	-	-	(5,595)
Acquisition of noncontrolling interest	-	-	(26,200)
Net cash provided by (used in) financing activities	16,530	(7,727)	(28,460)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(61,478)	(270)	(6,339)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	130,529	130,800	137,139
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$69,051	$130,529	$130,800
Supplemental disclosure of cash flow information			
Cash paid for Income taxes	$23,041	$34,444	$83,306

Supplemental disclosure of non cash investing and financing activities			
Property and equipment additions incurred during the period but not paid at period end	$18,983	$13,440	$9,814
Receivable from employees for stock option exercise	$-	$-	$173

See notes to consolidated financial statements.

F-5

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

VAALCO Energy, Inc., a Delaware corporation, is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. As used herein, the terms “Company” and “VAALCO” mean VAALCO Energy, Inc. and its subsidiaries, unless the context otherwise requires. VAALCO owns producing properties and conducts exploration activities as operator of consortiums internationally in Gabon and Angola and has conducted exploration activities as a non-operator in Equatorial Guinea, West Africa. Domestically, the Company has interests in Texas, Montana, Alabama, and the Gulf of Mexico.

VAALCO’s international subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., VAALCO International, Inc., VAALCO Energy (EG), Inc. and VAALCO Energy Mauritius (EG) Limited. VAALCO Energy (USA), Inc. holds interests in properties located in the United States.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - The accompanying consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The portion of the income and net assets applicable to the non-controlling interest in the majority-owned operations of the Company’s Gabon subsidiary has been reflected as noncontrolling interest. All intercompany transactions within the consolidated group have been eliminated in consolidation.

In December 2012, the Company acquired the noncontrolling interest in VAALCO International, Inc., for $26.2 million, with an effective date of October 1, 2012. Prior to the acquisition, the noncontrolling interest owned 9.99% of the issued and outstanding common stock of VAALCO International, Inc., a Delaware corporation of which VAALCO Gabon Etame, Inc. is the wholly owned subsidiary.

Cash and Cash Equivalents – Cash and cash equivalent includes deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase.

Restricted Cash – Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and time duration. Current amounts at December 31, 2014 each include an escrow amount representing the Company’s bank guarantees for customs clearance in Gabon ($1.6 million).Long term amounts at December 31, 2014 and 2013 each include the Company’s charter payment escrow for the Floating Production Storage and Offloading tanker (“FPSO”) in Gabon ($0.8 million) and funds restricted to secure the Company’s drilling obligation in Block 5 in Angola under the original production sharing contract ($10.0 million) and an increase of $10.0 million related to the Subsequent Exploration Phase (“SEP”) entered into in October 2014 which included two additional well obligations.

The Company invests restricted and excess cash in certificates of deposit and commercial paper issued by banks with maturities typically not exceeding 90 days.

Inventory - Materials and supplies are valued at the lower of cost, determined by the weighted-average method, or market. Crude oil inventories are carried at the lower of cost or market and represent the Company’s share of crude oil produced and stored on the FPSO, but unsold.

Income Taxes – VAALCO accounts for income taxes under an asset and liability approach that recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the financial statements and tax bases of assets and liabilities. Valuation allowances are provided against deferred tax assets that are not likely to be realized.

Property and Equipment - The Company follows the successful efforts method of accounting for exploration and development costs. Under this method, exploration costs, other than the cost of exploratory wells, are charged to expense as incurred. Exploratory well costs are initially capitalized until a determination as to whether proved reserves have been discovered. If an exploratory well is deemed to not have found proved reserves, the associated costs are expensed at that time. Other exploration costs, including geological and geophysical expenses applicable to undeveloped leasehold, leasehold expiration costs and delay rentals are expensed as incurred. All development costs, including developmental dry hole costs, are capitalized.

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred by capitalizing the corresponding cost as part of the carrying amount of the long-lived assets.

The Company reviews its oil and gas properties for impairment whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When it is determined that an oil and gas property's estimated future net cash flows will not be sufficient to recover its carrying amount, an impairment charge must be recorded to reduce the carrying amount of the asset to its estimated fair value. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors.

Depletion of wells, platforms, and other production facilities are calculated on a field basis under the unit-of-production method based upon estimates of proved developed producing reserves. Depletion of developed leasehold acquisition costs are provided on a field basis under the unit-of-production method based upon estimates of proved reserves. Undeveloped leasehold acquisition costs are not subject to depletion, but are subject to impairment testing. Provision for depreciation of other property is made primarily on a straight-line basis over the estimated useful life of the property. The annual rates of depreciation are as follows:

Office and miscellaneous equipment:	3 - 5 years
Leasehold improvements:	8 - 12 years

Foreign Exchange Transactions - For financial reporting purposes, the subsidiaries use the United States Dollar as their functional currency. Gains and losses on foreign currency transactions are included in income currently. The Company recognized loss on foreign currency transactions of $0.7 million in 2014. The Company recognized loss on foreign currency transactions of $0.1 million in 2013 and gains of $0.4 million in 2012, respectively.

Capitalized Interest - Interest costs from external borrowings are capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

Accounts With Partners - Accounts with partners represent cash calls due or excess cash calls paid by the partners for exploration, development and production expenditures made by VAALCO Gabon (Etame), Inc. and VAALCO Angola (Kwanza), Inc., and VAALCO (USA), Inc.

Bad Debt – On a quarterly basis, the Company evaluates its accounts receivable balances to confirm collectability. Where collectability is in doubt, the Company records an allowance against the accounts receivable balance with a corresponding charge to net income as bad debt expense. The majority of the Company's accounts receivable balances are with its joint venture partners and purchasers of its oil, natural gas and natural gas liquids and with the government of Gabon for reimbursements of Value-Added Tax ("VAT") paid by the Company. Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed to the Company. Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed to the Company.

During 2014 and 2013, the Company recorded a bad debt allowance of $2.4 million and $1.6 million, respectively. In 2014, the bad debt allowance pertains to VAT amounts owed for more than twelve months from the government of Gabon. In 2013, the bad debt allowance was related to the uncertainty in collecting its joint venture receivable in Angola as no joint venture partner was established. In January 2014, the Angolan government appointed Sonangol P&P as the replacement joint venture partner. The table below shows a rollforward analysis of the allowance against the partner accounts receivable balance and VAT: (in thousands)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Balance at End of Period
Allowance for Bad Debt			
Year Ended December 31, 2014	(7,631)	(2,400)	(10,031)
Year Ended December 31, 2013	(6,069)	(1,562)	(7,631)

Revenue Recognition – In May 2014, the Financial Accounting Standards Board ("FASB") issued revised guidance on revenue from contracts with customers, Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard provides a five-step analysis for transactions to determine when and how revenue is recognized. The guidance will be effective for us beginning January 1, 2017 and early adoption is not permitted. The guidance permits the use of either a full retrospective or a modified retrospective approach. We are evaluating the transition methods and the impact of the amended guidance on our financial position, results of operations and related disclosures.

The Company recognizes revenues from crude oil and natural gas sales upon delivery to the buyer. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. Revenue from the production of oil, natural gas and NGLs on properties in which we have joint ownership is recorded under the sales method. Under this method, we recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2014 and 2013, we had no oil and gas imbalances recorded in our consolidated financial statements.

Stock Based Compensation - The Company measures the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. Grant date fair value for options is estimated using an option-pricing model which is consistent with the terms of the award. For restricted stock, grant date fair value is determined using the grant date price of the company’s shares. Such cost is recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The Company estimates the number of instruments that will ultimately be issued, rather than accounting for forfeitures as they occur.

Fair Value of Financial Instruments - The Company’s financial instruments consist primarily of cash, restricted cash, trade receivables and trade payables and debt. The book values of cash, restricted cash, trade receivables, and trade payables are representative of their respective fair values due to the short-term maturity of these instruments. The book value of the Company’s debt instruments are considered to approximate the fair value, as the interest rates are adjusted based on rates currently in effect.

Fair Value – Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1 – Inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – Inputs that are not observable from objective sources, such as the Company’s internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company’s internally developed present value of future cash flows model that underlies the fair-value measurement).

Risks and Uncertainties - The Company's interests are located overseas in onshore and offshore Gabon, offshore in Angola and Equatorial Guinea, and domestically in Texas, Montana, Alabama, and the Gulf of Mexico.

Substantially all of the Company's oil and gas is sold at the well head at posted or indexed prices under short-term contracts, as is customary in the industry.

In Gabon, starting in the second quarter of 2014, the Company switched to an agency model to sell its crude oil. The Company contracted with a third party in order to sell, based on a fixed barrel fee, on the spot market. Prior to the second quarter in 2014, the Company sold oil under contracts with Mercuria Trading NV ("Mercuria") beginning with the calendar year 2011. For the first quarter of 2015, the Company will also sell its oil under the agency model on the spot market.

Domestic operated production in Texas is sold via two contracts, one for oil and one for gas and natural gas liquids. The Company has access to several alternative buyers for oil, gas, and natural gas liquids domestically.

Use of Estimates in Financial Statement Preparation - The preparation of financial statements in conformity with generally accepted accounting principles requires estimates and assumptions that affect the reported amounts of assets and liabilities as well as certain disclosures. The Company's consolidated financial statements include amounts that are based on management's best estimates and judgments. Actual results could differ from those estimates.

Estimates of oil and gas reserves used in the consolidated financial statements to estimate depletion expense and impairment charges require extensive judgments and are generally less precise than other estimates made in connection with financial disclosures. The Company considers its estimates to be reasonable; however, due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information become available.

Asset Retirement Obligations ("ARO") - The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore oil and gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with The Company's oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

3. STOCK BASED COMPENSATION

Stock options are granted under the Company's long-term incentive plan and have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted will become exercisable over a period determined by the Compensation Committee which in the past has been a five year life, with the options vesting over a service period of three to five years. A portion of the stock options granted in March 2014, 2013, and 2012 were vested immediately with the others vesting over a three year period. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. At December 31, 2014, there were 4,657,552 shares subject to options authorized but not granted.

For the years ended December 31, 2014, 2013 and 2012, the Company recognized non-cash compensation expense of $3.3 million, $3.0 million and $2.4 million, respectively. These amounts were recorded as general and administrative expense. Because the Company does not pay significant United States taxes, no amounts were recorded for tax benefits.

A summary of the stock option activity for the year ended December 31, 2014 is provided below:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in millions)
Outstanding at beginning of period	4,927	$ 6.95	2.85	2.81
Granted	1,118	$ 7.05	4.18	
Exercised	(1,128)	$ 5.04	0.69	
Forfeited	(152)	$ 7.47	3.54	
Outstanding at end of period	4,765	$ 7.41	2.62	$ 1.61
Vested - end of period	3,318	$ 7.45	2.22	$ 1.18
Vested and expected to vest - end of period	4,728	$ 7.41	2.62	$ 1.60

The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

Shares of restricted stock are granted under the Company’s long-term incentive plan using the fair market value of the underlying shares on the date of grant. In general, restricted stock granted to employees will vest over a period determined by the Compensation Committee. Determined by the Compensation Committee, some restricted stocks granted are vested immediately while some are vested over a three year period with the initial one-third vesting at the first grant date anniversary.

	Restricted Stock	Weighted Average Grant Price
Non-Vested Shares Outstanding December 31, 2013	100,000	$ 5.89
Awards granted	99,468	$ 6.98
Awards vested	(51,600)	$ 6.56
Awards forfeited	-	-
Non-Vested Shares Outstanding December 31, 2014	147,868	$ 6.39

As of December 31, 2014, unrecognized compensation costs totaled $2.8 million. The expense is expected to be recognized over a weighted average period of 2.5 years.

A summary of the values of options granted and exercised for each of the years ended December 31, 2014, 2013 and 2012 is provided below:

	2014	2013	2012
Options granted - (thousands)	1,118	1,836	1,024
Weighted average grant date fair value - ($/share)	$2.43	$2.45	$3.49
Weighted average exercise price - ($/share)	$5.04	$4.25	$4.62
Options exercised (thousands)	1,128	877	759
Total intrinsic value of options exercised - ($thousands)	$4,120	$1,201	$3,267

The Company received cash proceeds of $5.7 million, $3.7 million and $3.3 million from issuance of stock related to options exercised in 2014, 2013 and 2012, respectively.

The valuation of the options granted is based upon a Black Scholes model. The table below summarizes the assumptions used to value the options issued in 2014 and 2013.

Year	Options Issued (in thousands)	Average Volatility	Expected Term	Risk Free Interest Rate	Expected Dividend Yield
2014	1,118	58%	2.5 years	0.5%	0%
2013	1,836	51%	2.5 years	0.3%	0%
2012	1,024	65%	2.5 years	0.5%	0%

The Company has no set policy for sourcing shares for options grants. Historically the shares issued under options grants have been new shares.

4. STOCKHOLDERS' EQUITY AND EARNINGS PER SHARE

The Company is authorized to issue up to 100 million shares of common stock. Basic earnings per share ("EPS") is calculated using the average number of shares of common stock outstanding during each period. Diluted EPS assumes the restricted stock is outstanding on the date of the grant and the exercise of all stock options having exercise prices less than the average market price of the common stock using the treasury stock method.

A reconciliation of diluted shares consists of the following:

	Year Ended December 31,		
	2014	2013	2012
Item			
Basic weighted average common stock issued and outstanding	57,229,435	57,298,910	57,673,342
Dilutive options and restricted stock	-	626,091	1,158,717
Total diluted shares	57,229,435	57,925,001	58,832,059

A total of 2,329,392, 3,508,865, and 1,018,900 shares under option were not included because they were anti-dilutive during the years ended December 31, 2014, 2013 and 2012, respectively.

5. INCOME TAXES

The Company and its domestic subsidiaries file a consolidated United States income tax return. Certain subsidiaries' operations are also subject to foreign income taxes.

Provision for income taxes consists of the following:

(in thousands)	Year Ended December 31,		
	2014	2013	2012
U.S. Federal:			
Current	$-	$-	$-
Deferred	-	-	-
Foreign:			
Current	22,486	34,115	81,813
Deferred	-	-	-
Total	$22,486	$34,115	$81,813

The primary differences between the financial statement and tax bases of assets and liabilities at December 31, 2014 and 2013 are as follows: (In thousands)

	2014	2013
Deferred Tax Assets:		
Basis difference in fixed assets	$63,931	$31,440
Foreign tax credit carry forward	48,928	55,908
Alternative minimum tax credit carryover	1,349	1,349
Foreign net operating losses	44,228	42,688
Asset retirement obligations	5,196	4,012
Other	3,828	3,300
	$167,460	$138,697
Valuation allowance	(166,111)	(137,348)
Total deferred tax asset	$1,349	$1,349

The Company's unused foreign tax credits will start to expire between the years 2017 and 2023. The alternative minimum tax credits do not expire, and foreign net operating losses ("NOL") are not subject to expiry dates. The NOL for the Company's UK subsidiary can be carried forward indefinitely, while the NOLs for the Company's Gabon and Angola subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. The Company does not anticipate utilization of the foreign tax credits prior to expiration nor does the Company expect to generate sufficient taxable income to utilize other deferred tax assets. On the basis of this evaluation, a valuation allowance of $166.1 million and $137.3 million has been recorded as of December 31, 2014 and 2013, respectively, to reduce the deferred tax asset to the amount that is more likely than not to be realized.

Under U.S. tax law, certain foreign taxes paid under arrangements such as the Company's Production Sharing Contracts ("PSCs") may not be eligible to be claimed as foreign tax credits and are instead treated as deductible royalties. In 2013, the Company engaged outside advisors to analyze the facts and circumstances surrounding the creditability of the foreign taxes paid to the Republic of Gabon pursuant to its PSC. Based on the advice provided by these outside advisors, the Company revised its estimate of foreign tax credit carryovers in 2013 to reflect an increase of $28.0 million. The increase in deferred tax asset for foreign tax credits was fully offset by an increase in the valuation allowance.

Pretax income (loss) is comprised of the following:

(in thousands)	Year Ended December 31,		
	2014	2013	2012
United States	$(6,349)	$(17,649)	$(56,979)
Foreign	(48,715)	94,836	144,131
	$(55,064)	$77,187	$87,152

The statutory rate reconciliation is as follows:

(In Thousands)	Year Ended December 31,		
	2014	2013	2012
Tax Provision Computed at Statutory Rate	$(19,273)	$27,015	$30,503
Foreign taxes not offset in U.S. by foreign tax credits	4,433	(2,072)	25,266
Permanent Differences	135	973	2,370
Foreign Tax Credit Adjustments	8,417	(28,027)	
Increase/(Decrease) in Valuation Allowance	28,762	37,752	23,675
Other	12	(1,526)	-
Total Tax Expense	$22,486	$34,115	$81,813

At December 31, 2014, the Company was subject to foreign and United States federal taxes only, with no allocations made to state and local taxes.

The following table summarizes the tax years that remain subject to examination by major tax jurisdictions:

United States	2008-2014
Gabon	2007-2014

6. COMMITMENTS AND CONTINGENCIES
FPSO Charter

In October 2012, the Company entered into an amendment with the owner of the FPSO chartered for the Etame field to extend the contract until September 2020. In connection with the charter of the FPSO, the Company, as operator of the Etame field, guaranteed the charter payments through the same period. The charter continues for two years beyond that period unless one year's prior notice is given to the owner of the FPSO. The Company obtained several guarantees from its partners for their share of the charter payment. The Company's share of the charter payment is 28.1%. The Company believes the need for performance under the charter guarantee is remote.

The estimated obligations for the annual charter payment and the Company's share of the charter payments through the end of the charter are as follows: (in thousands)

Year	Full Charter	Company Share

	Payment	
2015	$25,843	$7,255
2016	25,843	7,255
2017	25,843	7,255
2018	25,843	7,255
2019	25,843	7,255
Thereafter	25,914	7,275
Total	$155,129	$43,550

The Company has recorded a liability of $1.0 million and $1.1 million at December 31, 2014 and 2013, respectively, representing the guarantee's fair value.

The Company's share of charter expense, including a $0.93 per Bbl ($0.25 per Bbls in 2013) charter fee for production up to 20,000 BOPD and a $2.50 per Bbl charter fee for those Bbls produced in excess of 20,000 BOPD, was $11.8 million, $10.4 million and $9.7 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Other Lease Obligations

In addition to the FPSO, the Company has operating lease obligations for rentals as follows: (in thousands)

Year	Gross Obligation	Company Share
2015	$ 90,935	$ 36,812
2016	36,607	10,594
2017	441	441
2018	408	408
2019	407	407
Thereafter	340	340
Total	$ 129,138	$ 49,002

The Company contracted with two drilling rigs in the year ended December 31, 2014. In the third quarter of 2014, the Company contracted with a drilling rig to begin a multi- well development drilling campaign offshore Gabon. The campaign includes drilling of wells from the Etame platform and wells from the South East Etame and North Tchibala platform. The drilling rig commenced in October 2014 and provides a commitment until July 2016, at a day rate of approximately $168,000. The total commitment related to this rig is $25.8 million. The second drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well began drilling in the first quarter of 2015. The drilling rig provides a forty-five day commitment at a day rate of approximately $338,000. The total commitment related to this rig is $15.2 million Such rates are subject to standard reimbursement and escalation contractual provisions.

The 2015 lease obligation amounts are higher than amounts for years beyond 2015 due to short term contracts for helicopter and marine vessels supporting the offshore Gabon operations.

The Company incurred rent expense of $4.0 million, $4.1 million and $4.4 million under operating leases for the years ended December 31, 2014, 2013 and 2012, respectively.

Gabon Obligation

Under the terms of the Etame Production Sharing Contract, the consortium is required to provide to the local government refinery a volume of crude at a 25% discount to market price (the “Gabon Obligation”). The volume required to be furnished is the amount of the Etame Marin block production divided by the total Gabon production times the volume of oil refined by the refinery per year. In 2014, the Company paid $3.3 million for its share of the 2013 obligation. In 2013, the Company paid $3.0 million for its share of the 2012 obligation. In 2012, the Company paid $3.7 million for its share of the 2011 obligation. The Company accrues an amount for the Gabon Obligation based on management’s best estimate of the volume of crude required, because the refinery does not publish its throughput figures. The amount accrued at December 31, 2014, for the Company’s share of the 2014 obligation is $2.7 million. These costs are deemed cost recoverable under the terms of the production sharing contract.

Offshore Gabon

As part of securing the first of two-five year extensions to the Etame field production license to which the Company is entitled from the government of Gabon, the Company agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin Block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding for the next seven years at 12.14% of the total abandonment estimate per year and 5.0% per year for the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The initial funding took place in October 2014 for calendar years 2012 and 2013 totaling $8.4 million ($2.3 million net to the Company). The funding for calendar year 2014 was paid in the first quarter of 2015 in the amount of $4.2 million ($1.2 million net to the Company). The abandonment estimate for this purpose is estimated to be approximately $10.1 million net to the Company on an undiscounted basis. As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company's balance sheet. The cash funding is reflected under other long term assets as "Abandonment Funding".

Additionally, in October 2014, the Company received a provisional audit report related to the Etame Marin block operations from the Gabon Taxation Department as part of a special industry-wide audit of business practices and financial transactions in the Republic of Gabon. The Company currently cannot reasonably estimate a range of potential loss, if any, as a result of the audits. While the ultimate outcome of the claim and impact on VAALCO cannot be predicted, management believes that the claims are unfounded. In November 2014, we responded to the Gabon Taxation Department requesting joint meetings to advance the resolution of this matter and provided a formal reply to the provisional audit report in February 2015.

Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Additional extensions were subsequently granted by the Angolan government until November 30, 2014 to drill the two exploration commitment wells.

In the fourth quarter of 2013, the Company received written confirmation from The Ministry of Petroleum of Angola that the available 40% working interest in Block 5, offshore Angola, was assigned to Sonangol E.P., the National Concessionaire. The Ministry of Petroleum also confirmed that Sonangol E.P. would assign the aforementioned participating interest to its exploration and production affiliate, Sonangol P&P.

In April 2014, the Company received a letter and contractual amendment proposal from Sonangol E.P., related to the extension of the two well drilling commitment, prior to the expiration of the extension on November 30, 2014, by the government of Angola. Due to the uncertainty that the primary term of the exploration license would be extended by the Republic of Angola before the November 30, 2014 expiration date, in October 2014, the Company entered into the Subsequent Exploration Phase ("SEP"), together with its working interest partner, Sonangol P&P. The Subsequent Exploration Phase ("SEP") provided for in the Production Sharing Agreement signed in 2006 with the Republic of Angola. The SEP extends the exploration period for an additional three year period such that the new expiry date for exploration activities is November 30, 2017. Entering the SEP requires the Company and its partner to acquire 3D seismic covering six hundred square kilometers and to drill two additional exploration wells.

Late in 2013, the Company proceeded to obtain additional seismic data covering the deeper segment of the block. The seismic data was reprocessed during 2014 and will continue to be reprocessed in 2015. With the purchase of the additional seismic data, the Company has already satisfied the seismic obligation of the SEP.

By entering into the SEP, the Company is required to drill a total of four exploration wells during the exploration extension period. The four well obligations include the two well commitments under the primary exploration period that carries over to the SEP period. A $10.0 million dollar assessment ($5.0 million dollars net to VAALCO) applies to each of the four commitment exploration wells, if any, that remain undrilled at the end of the exploration period in November 2017. Restricted cash of $10.0 million for the two new commitment wells was recorded in the fourth quarter of 2014. At December 31, 2014 the Company had $20.0 million in restricted cash related to the offshore Angola exploration agreement.

A drilling rig contract was signed in July 2014 for a semi-submersible rig to drill the exploration well on the Kindele prospect, a post-salt objective. The well is expected to begin drilling in the first quarter of 2015. Drilling this well will satisfy one of the four exploration well obligations and release $5.0 million of the $20.0 million recorded as restricted cash at December 31, 2014 by the Company.

7. LONG TERM DEBT

In January 2014, the Company executed a loan agreement with the International Finance Corporation ("IFC") for a $65.0 million revolving credit facility, which is secured by the assets of the Company's Gabon subsidiary. Borrowings under the credit facility totaled $15.0 million as of December 31, 2014 and are due in full upon maturity in December 2019. The borrowings approximate fair value as the interest approximates current market rates for similar instruments. In the year ended 2014, the interest rate on the Company's bank debt averaged 4.32%. The debt facility is secured by the assets and ownership of the

Company’s Gabon subsidiary ($58.7 million net asset value as of December 31, 2014) and include a parent company guarantee.

Under the debt agreement the senior tranche decreases by $6.25 million and the subordinated tranche decreases by $1.88 million every six months beginning June 30, 2016 through December 2019. The proceeds from any borrowings under the facility are required to be used for (i) the construction of two new platforms and associated facilities in the Etame field and the South East Etame and North Tchibala fields; (ii) the drilling, completion and production of wells for the aforementioned fields; (iii) upon approval, the Ebouri Project; (iv) the costs associated with modifying the FPSO to support the new platforms, all of which are located in the Etame Block offshore of the southern coast of Gabon; and (v) general corporate purposes related to the foregoing.

Interest is paid quarterly at a rate of LIBOR plus a spread of 3.75% for the senior tranche and 5.75% for the subordinated tranche. We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 1.5% of the unused balance of the senior tranche of $50.0 million and 2.3% of the unused balance of the subordinated tranche of $15.0 million when a commitment is available for utilization.

Our borrowing base under the IFC credit facility is based upon our proved reserves and risk adjusted probable reserves and is re-determined semi-annually by the IFC. In addition, the borrowing base may be adjusted pursuant to certain non-scheduled re-determinations. However, the credit facility contains a covenant that prevents us from borrowing any amounts that would cause our debt to equity ratio to exceed 60:40. As of December 31, 2014, we estimate that this covenant would restrict our total borrowing capacity to approximately $25.0 million (of which $15.0 million has been borrowed as of December 31, 2014).

Under the IFC credit facility, we are required to maintain a ratio of our net debt to EBITDAX (each as defined in the credit agreement) of not more than 3.0 to 1.0 and a ratio of debt to equity at or below 60:40. Forecasting our compliance with the financial covenant in future periods is inherently uncertain. Factors that could impact our debt to EBITDAX in future periods include future realized prices for sales of oil and natural gas, estimated future production, returns generated by our capital program, and future interest costs, among others. The Company is in compliance with all financial covenants at the end of December 31, 2014.

The credit agreement governing the IFC credit facility contains additional customary non-financial covenants that, among other things, restrict our ability to pay dividends, restrict our ability to buy and sell assets, limit our ability to make acquisitions or investments, and restrict our ability to incur additional indebtedness. In addition, the credit agreement contains administrative requirements, including but not limited to providing financial statements, compliance certificates, and other documents to the IFC under prescribed timelines.

Subject to any cure periods, the consequences of non-compliance with our debt covenants generally include, but are not limited to, the ability of the IFC to accelerate our obligation to repay amounts outstanding.

8. CAPITALIZATION OF INTEREST

The Company capitalizes interest costs and commitment fees on expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest and commitment fees are capitalized only for the period that activities are in progress to bring these projects to their intended use. For year ended December 31, 2014, the Company incurred interest expense of $1.2 million, in connection with the IFC credit facility. All interest expense was capitalized.

9. CAPITALIZATION OF EXPLORATORY WELL COSTS

ASC Topic 932 - Extractive Industries provides that an exploratory well shall be capitalized as part of the entity's uncompleted wells pending the determination of whether the well has found proved reserves. Further, an exploration well that discovers oil and gas reserves, but those reserves cannot be classified as proved when drilling is completed, shall be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, the exploration well would be assumed to be impaired and its costs would be charged to expense.

	2014	2013	2012
Capitalized exploratory well costs that have been capitalized for a period less than one year		-	5.9
Capitalized exploratory well costs that have been capitalized for a period greater than one year	8.9	16.7	8.1
Total	8.9	16.7	14.0
Number of exploratory wells that have been capitalized for a period greater than one year	1	2	1

In the second and third quarters of 2010, the Company drilled the Southeast Etame No. 1 well with two sidetracks in the Etame Marin block offshore Gabon. The well discovered five meters of oil-sand. Additional evaluation of the well and sidetrack information was conducted to facilitate options for developing the discovery. The Company and its joint venture partners evaluated the merits of two development options. One option involved a subsea well to develop the Southeast Etame discovery only, whereas the second option envisioned a platform development to access both the Southeast Etame area as well as the North Tchibala field, where a discovery was made on the block prior to VAALCO's block participation. In the second quarter of 2012, the Company and its partners agreed to proceed with the development plan featuring a fixed leg platform for developing the Southeast Etame discovery area and the North Tchibala field and the final investment decision was approved in the fourth quarter of 2012 for the construction of the platform. The platform was completed and installed in the third quarter of 2014. A drilling rig has been contracted to drill a development well in the Southeast Etame field in the first half of 2015. Due to the recent fall in oil prices, the Company recognized an impairment loss in the Southeast Etame field in the fourth quarter of 2014. The impairment resulted in a $7.8 million write off related to the Southeast Etame No.1 well. Accordingly, the well has been removed from the above schedule for 2014.

In the third and fourth quarters of 2012, the Company drilled the N'Gongui No. 2 well with three sidetracks in the Mutamba Iroru block onshore Gabon. Evaluation of the well and sidetrack information was performed in the second quarter of 2013. A revised production sharing contract ("PSC") including exploration rights is in the approval process. The term sheet, which specifies financial and other obligations to be included in the PSC, was agreed to and signed by the Company, its joint venture partner, and the Government of Gabon on July 31, 2014. The form of the PSC has been completed and presented to the Company and its joint venture partner for execution. The joint venture partner has withheld its approval of the new PSC pending resolution of certain legal aspects of the new agreement with the Government of Gabon. In March 2015, the joint venture partner indicated to the Company that the legal aspects have not yet been resolved to their satisfaction. The Company can provide no assurance as to the joint venture partner approving the PSC. The Company remains committed to this block and further meetings of the parties are expected to occur in the first half of 2015.

After the PSC is approved, an application for a development area will be made by the Company. After issuance of a development area, the next step is the submittal of the plan of development. The Company can provide no assurances as to the either the approval of the PSC by the Government of Gabon, or the subsequent approval of a development area by the Government of Gabon. The Company has capitalized $8.9 million for the discovery well in accordance with the criteria contained in ASC Topic 932.

10. EMPLOYEE BENEFIT PLANS

The Company sponsors a 401(k) plan, with a Company match feature, for its employees. Costs incurred in 2014, 2013 and 2012 for administering the plan, including the Company match feature, were approximately $464,000, $182,500 and $204,000, respectively.

11. ASSET RETIREMENT OBLIGATIONS

The fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred by capitalizing it as part of the carrying amount of the long-lived assets. The Company records asset retirement obligations for the future abandonment costs of tangible assets such as platforms, wells, pipelines and other facilities. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

A summary of the recording of the estimated fair value of the Company's asset retirement obligations is presented as follows:

(In Thousands)	Year Ended December 31,		
	2014	2013	2012
Balances at January 1,	$11,464	$10,368	$14,528
Accretion Expense	720	643	814
Additions	2,526	453	770
Revisions	136	-	(5,744)
Balance December 31,	$14,846	$11,464	$10,368

During the year ended December 31, 2014, the Company increased the asset retirement obligations to recognize the abandonment liability for two new platforms and two wells offshore Gabon. In the year ended December 31, 2013, the Company increased the asset retirement obligations to recognize the abandonment liability for two wells offshore Gabon. The 2012 cost revision of $5.7 million was primarily due to changes in asset retirement cost estimates on the Etame block offshore Gabon.

The Company does not plan to abandon any material assets over the next five years.

12. SEGMENT INFORMATION

The Company's operations are based in Gabon, Angola, Equatorial Guinea and the United States. The chief operating decision maker, the CEO and management review and evaluates the operation of each geographic segment separately. The operations of all segments include exploration for and production of hydrocarbons where commercial reserves have been found and developed. The accounting policies of the reportable segments are the same as in Note 2. Revenues are based on the location of hydrocarbon production. The Company evaluates each segment based on income (loss) from operations. Segment activity for the years ended December 31, 2014, 2013 and 2012 are as follows: (in thousands)

2014	Gabon	Angola	Equatorial Guinea	USA	Corporate and Other	Total
Revenues	$126,322	$-	$ -	$1,369	$ -	$127,691
Depreciation, depletion and amortization	19,079	12	-	901	94	20,086
Operating income (loss)	(42,105)	(3,798)	(1,525)	(119)	(6,859)	(54,406)
Interest income	42	-	-	-	33	75
Income taxes	22,486	-	-	-	-	22,486
Bad debt and other expenses	2,400	-	-	-	-	2,400
Impairment of proved properties	98,341	-	-	-	-	98,341

Additions to properties and equipment	83,170	3,117	-	8	816	87,111
Long lived assets	76,247	14,645	10,000	6,359	873	108,124
Total assets	192,957	22,305	10,197	6,611	16,779	248,849

2013	Gabon	Angola	Equatorial Guinea	USA	Corporate and Other	Total
Revenues	$167,386	$-	$ -	$1,891	$ -	$169,277
Depreciation, depletion and amortization	15,310	28	-	1,528	63	16,929
Operating income (loss)	98,795	(3,018)	(768)	(11,869)	(5,915)	77,225
Interest income	40	-	-	-	33	73
Income taxes	34,115	-	-	-	-	34,115
Bad debt and other expenses	1,764	1,562	-	-	-	3,326
Additions to properties and equipment	53,015	629	-	-	47	53,691
Long lived assets	109,597	11,540	10,000	7,235	152	138,524
Total assets	256,033	12,204	10,059	9,660	20,211	308,167

F-17

2012	Gabon	Angola	Equatorial Guinea	USA	Corporate and Other	Total
Revenues	$192,489	$-	$ -	$2,798	$ -	$195,287
Depreciation, depletion and amortization	15,954	28	-	3,872	59	19,913
Operating income (loss)	147,985	(3,293)	(754)	(48,940)	(8,405)	86,593
Interest income	60	(1)	-	-	86	145
Income taxes	81,813	-	-	-	-	81,813
Bad debt and expenses	-	1,621	-	-	-	1,621
Impairment of proved properties	-	-	-	7,620	-	7,620
Additions to properties and equipment	22,731	-	10,000	13,558	77	46,366
Long lived assets	71,225	10,938	10,000	14,279	166	106,608
Total assets	190,652	11,405	10,000	17,314	38,585	267,956

Information about our most significant customers

In Gabon, starting in the second quarter of 2014, the Company switched to an agency model to sell its crude oil. The Company contracted with a third party in order to sell, based on a fixed barrel fee, on the spot market. Prior to the second quarter in 2014, the Company sold oil under contracts with Mercuria Trading NV ("Mercuria") beginning with the calendar year 2011. For the first quarter of 2015, the Company will also sell its oil under the agency model on the spot market.

13. IMPAIRMENT OF PROVED PROPERTIES

The Company reviews its oil and gas producing properties for impairment whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When it is determined that an oil and gas property's estimated future net cash flows will not be sufficient to recover its carrying amount, an impairment charge is recorded to reduce the carrying amount of the asset to its estimated fair value.

Accordingly, impairment testing was performed using the year end 2014 independently prepared reserve report and forward price curves. The Company performed a recoverability test as defined under ASC 932 and ASC 360, noting that the undiscounted cash flows related to the Etame, Ebouri and Southeast Etame/North Tchibala fields were less than the book values for these fields resulting in the Company recording an impairment loss of $98.3 million to write down its investment in the Etame Marine Block, offshore Gabon to its fair value. Impairment of $38.5 was recorded in the Etame field, $5.9 million in the Ebouri field and $53.9 million in the Southeast Etame/North Tchibala field. The impairment is a result of the recent decline in the forecasted oil prices used in the impairment testing and calculation.

The measurement of these assets at fair value is calculated using discounted cash flow techniques and based on estimates of future revenues and costs associated with Ebouri field. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of future crude oil and natural gas prices, production costs, and anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. For crude oil, estimates were based on NYMEX Brent Ice Intermediate prices, adjusted for quality, transportation fees, and market differential.

The Company determined no impairment charge was necessary 2013.

In 2012, the Company recorded an impairment loss of $7.6 million in the United States to write down the value of its Hefley field in the Granite Wash formation to its estimated fair value. The initial measurement of these assets at fair value is calculated using discounted cash flow techniques and based on estimates of future revenues and costs associated with the Granite Wash formation well. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of future crude oil and natural gas prices, production costs, development expenditures, and anticipated production of proved and probable reserves, appropriate risk-adjusted discount rates and other relevant data. For crude oil, estimates were based on NYMEX West Texas Intermediate prices, adjusted for quality, transportation fees, and a regional price differential. For natural gas, estimates were based on NYMEX Henry Hub prices, adjusted for energy content, transportation fees, and a regional price differential.

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following represents our unaudited quarterly results for years ended December 31, 2014 and 2013. The quarterly results were prepared in accordance with accounting principles generally accepted in the United States of America, and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature.

(In thousands of dollars except per share information)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2014				
Total revenues (1)	$ 28,071	$ 52,098	$ 24,486	$ 23,037
Total operating costs and expenses	28,721	18,270	17,799	117,308
Operating income (loss)	(650)	33,828	6,687	(94,270)
Net income (loss)	(7,038)	24,712	3,109	(98,332)
Basic net income (loss) per share	$ (0.12)	$ 0.43	$ 0.05	$ (1.70)
Diluted net income (loss) per share	$ (0.12)	$ 0.43	$ 0.05	$ (1.70)

(In thousands of dollars except per share information)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2013				
Total revenues (1)	$ 44,137	$ 29,118	$ 37,740	$ 58,282
Total operating costs and expenses	22,634	17,452	29,636	22,331
Operating income	21,503	11,666	8,104	35,951
Net income	7,188	7,121	2,386	26,377
Basic net income per share	$ 0.12	$ 0.12	$ 0.04	$ 0.46
Diluted net income per share	$ 0.12	$ 0.12	$ 0.04	$ 0.46

(1) Gabon crude oil sales are a function of the number and size of crude oil liftings in each quarter from the floating production, storage and offloading ("FPSO") facility.

Quarterly income per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and issuance of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

15. SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following information is being provided as supplemental information in accordance with certain provisions of ASC Topic 932 – Extractive Activities- Oil and Gas. The Company's reserves are located offshore of Gabon and in Texas. The following tables set forth costs incurred, capitalized costs, and results of operations relating to oil and natural gas producing activities for each of the periods. (See Footnote 1 – "ORGANIZATION")

Costs Incurred in Oil and Gas Property

Acquisition, Exploration and Development Activities

(In thousands)	United States		
	2014	2013	2012
Costs incurred during the year:			
Exploration - capitalized	$-	$-	$2,602

Exploration - expensed	-	11,497	38,159
Acquisition	-	-	1,630
Development	8	113	9,689
Total	$8	$11,610	$52,080

(In thousands)	International		
	2014	2013	2012
Costs incurred during the year:			
Exploration - capitalized	$-	$2,942	$5,916
Exploration - expensed	15,358	12,431	2,878
Acquisition	-	-	10,000
Development	79,722	54,420	4,022
Total	$95,080	$69,793	$22,816

Exploration expense includes $13.3 million, $23.9 million and $37.3 million for dry hole expense in 2014, 2013 and 2012, respectively. The dry hole expense for 2014 was attributable to one unsuccessful exploration well spudded in the fourth quarter of

2013 and determined to be a dry hole in the first quarter of 2014 in Gabon for $11.7 million and $1.6 million in leasehold costs related to the expiration of the exploration license offshore Gabon.

In November 2012, the Company completed the acquisition of a 31% working interest in Block P located offshore in Equatorial Guinea at a cost of $10.0 million.

Capitalized Costs Relating to Oil and Gas Producing Activities:

	December 31, 2014	2013	2012
Capitalized costs -			
Properties not being amortized	$47,290	$88,194	$66,794
Properties being amortized (1)	347,186	222,032	195,329
Total capitalized costs	$394,476	$310,226	$262,123
Less accumulated depreciation, depletion, and amortization	(289,272)	(171,854)	(155,681)
Net capitalized costs	$105,204	$138,372	$106,442

(1) Includes $5.2 million, $5.2 million, and $4.7 million asset retirement cost in 2014, 2013, and 2012, respectively. The capitalized costs pertain to the Company's producing activities in Gabon, leasehold acreage in Gabon, Angola, and Equatorial Guinea, and U.S. activities.

Results of Operations for Oil and Gas Producing Activities:

	United States 2014	2013	2012	International 2014 Gabon	2013 Gabon	2012 Gabon
Crude oil and gas sales	$1,369	$1,891	$2,798	$126,322	$167,386	$192,489
Production, G&A and other expense	(467)	(12,232)	(47,866)	(150,602)	(52,776)	(27,425)
Depreciation, depletion and amortization	(901)	(1,528)	(3,872)	(19,079)	(15,302)	(15,954)
Income tax	-	-	-	(22,486)	(34,115)	(81,813)
Results from oil and gas producing activities	$1	$(11,869)	$(48,940)	$(65,845)	$65,193	$67,297

Proved Reserves

Reserve reports as of December 31, 2014, 2013, and 2012 have been prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The following tables set forth the net proved reserves of the Company as of December 31, 2014, 2013 and 2012, and the changes during such periods.

Proved Reserves:	Oil (MBbls)	Gas (MMCF)

Balance at January 1, 2012	6,048	1,925
Production	(1,741)	(532)
Revisions of previous estimates	2,200	151
Extensions and discoveries	981	-
Balance at December 31, 2012	7,488	1,544
Production	(1,549)	(325)
Revisions of previous estimates	771	114
Extensions and discoveries	522	-
Balance at December 31, 2013	7,232	1,333
Production	(1,351)	(227)
Revisions of previous estimates	2,312	300
Extensions and discoveries	67	-
Balance at December 31, 2014	8,260	1,406

Proved Developed Reserves	Oil (MBbls)	Gas (MMCF)
Balance at January 1, 2012	3,854	856
Balance at December 31, 2012	3,750	1,544
Balance at December 31, 2013	3,305	1,333
Balance at December 31, 2014	3,224	1,406

The Company's proved developed reserves are located offshore Gabon and in Alabama, Texas and waters of the Gulf of Mexico. Revisions in 2014 were primarily due to better reservoir performance at the Avouma/South Tchibala field (1,500 MBbls) and a combination of better reservoir performance from existing wells at Etame, and revisions to proved undeveloped reserves at Etame (1,100 MBbls). Ebouri proved undeveloped reserves were revised downward (300 MBbls) due to higher costs of developing the reserves rendering them uneconomic. Revisions in 2013 were primarily due to better reservoir performance at the Etame field (800 MBbls). In 2012, the revisions were due to improved reservoir performance at the Avouma/South Tchibala field (1,200 MBbls) and improved reservoir performance at Etame (1,000 MBbls). In 2014, the extensions and discoveries were associated with the booking of the Southeast Etame/North Tchibala reserves. Extensions and discovery reserve additions in 2013 were due to the drilling of the Avouma 3H well which extended the reservoir boundary further to the north at the Avouma field. In 2012, the extensions and discoveries were associated with the booking of the Southeast Etame/North Tchibala reserves following approval of the development plans for these fields and final investment decision to install the platforms necessary to develop these fields.

The Company maintains a policy of not booking proved reserves on discoveries until such time as a development plan has been prepared for the discovery. Additionally, the development plan is required to have the approval of the Company's partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

Standardized Measure of Discounted Future Net Cash

Flows Relating to Proved Oil Reserves

The information that follows has been developed pursuant to procedures prescribed by ASC Topic 932 and utilizes reserve and production data estimated by independent petroleum consultants. The information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating VAALCO Energy, Inc. or its performance.

In accordance with the guidelines of the SEC, the Company's estimates of future net cash flow from the Company's properties and the present value thereof are made using oil and gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. Future development costs include $52.8 million ($14.8 million net to the Company) attributable to future abandonment when the wells become uneconomic to produce.

(In thousands)	United States			International			Total		
	December 31,			December 31,			December 31,		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Future cash inflows	$9,598	$8,276	$8,260	$814,059	$725,485	$776,646	$823,657	$733,761	$784,906
Future production costs	(1,475)	(3,038)	(3,194)	(307,331)	(223,643)	(203,490)	$(308,806)	(226,681)	(206,684)
Future development costs	-	-	-	(136,137)	(164,142)	(186,982)	(136,137)	(164,142)	(186,982)
Future income tax expense	(359)	(825)	(807)	(177,924)	(154,519)	(181,194)	$(178,283)	(155,344)	(182,001)
Future net cash flows	$7,764	$4,413	$4,259	$192,667	$183,181	$204,980	$200,431	$187,594	$209,239
Discount to present value at 10% annual rate	(3,516)	(1,299)	(1,028)	(47,528)	(48,859)	(55,309)	$(51,044)	(50,158)	(56,337)
Standardized measure of discounted future net cash flows	$4,248	$3,114	$3,231	$145,139	$134,322	$149,671	$149,387	$137,436	$152,902

International income taxes represent amounts payable to the Government of Gabon on profit oil as final payment of corporate income taxes, and domestic income taxes (including other expenses treated as taxes), and domestic income taxes represent amounts payable for severance and ad-valorem taxes in Texas.

Changes in Standardized Measure of Discounted Future Net Cash Flows:

The following table sets forth the changes in standardized measure of discounted future net cash flows as follows:

(In thousands)	December 31, 2014	2013	2012
Balance at Beginning of Period	$137,436	$152,902	$166,187
Sales of oil and gas, net of production costs	(95,973)	(132,662)	(168,563)
Net changes in prices and production costs	(28,098)	(52,056)	(11,223)
Revisions of previous quantity estimates	74,497	43,815	155,111
Additions	2,188	29,620	69,092
Changes in estimated future development costs	31,686	(5,345)	(67,834)
Development costs incurred during the period	-	44,389	34,944
Accretion of discount	24,163	15,290	16,619
Net change of income taxes	(15,609)	26,120	7,445
Change in production rates (timing) and other	19,097	15,363	(48,876)
Balance at End of Period	$149,387	$137,436	$152,902

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the Company. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place remain the property of the Gabon government.

In accordance with the guidelines of the Securities and Exchange Commission, the Company's estimates of future net cash flow from the Company's properties and the present value thereof are made using oil and gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. In Gabon, the weighted average price was $98.88 per Bbl. In the United States, the weighted average price was $86.49 per Bbl of oil and $5.19 per Mcf of gas.

Under the Production Sharing Contract in Gabon, the Gabonese government is the owner of all oil and gas mineral rights. The right to produce the oil and gas is stewarded by the Directorate Generale de Hydrocarbures and the Production Sharing Contract was awarded by a decree from the State. Pursuant to the service contract, the Gabon government receives a fixed royalty rate of 13%.

The consortium maintains a Cost Account, which entitles it to receive 70% of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account. At December 31, 2014, there was $36.8 million in the cost account net to the Company. As payment of corporate income taxes the consortium pays the government an allocation of the remaining “profit oil” production from the contract area ranging from 50% to 60% of the oil remaining after deducting the royalty and the cost oil. The percentage of “profit oil” paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, the Company only recovers ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. The Cost Account has been substantially recovered since the first quarter of 2005. In 2012, the Company cost recovered 367,000 barrels out of a theoretical 1,197,000 barrels which would have been recoverable if the Cost Account was full. In 2013, the Company cost recovered 929,400 barrels out of a theoretical 1,079,300 barrels which would have been recoverable if the Cost Account was full. In 2014, the Company cost recovered 907,400 barrels out of a theoretical 935,800 barrels which would have been recoverable if the Cost Account was full.

Also because of the nature of the Cost Account, increases in oil prices result in a lesser number of barrels required to recover costs, therefore at higher oil prices, the Company’s net reserves after taxes would decrease, but at lower prices the Company’s Cost Oil barrels increase.

The Etame Production Sharing Contract allows for the carve-out of a development area, which was performed for the Etame, Avouma/South Tchibala, and Ebouri fields. The Etame development area has a term of 20 years and will expire in 2021 which coincidentally matches the economic life of the Etame reserves under the current reserve report prepared by our independent reserves engineering firm. The Avouma/South Tchibala field development area has a term of 20 years and will expire in 2025. The Ebouri field development area has a term of 20 years and will expire in 2026. The balance of the Etame Marin block comprises the exploration area, which expired in July 2014.

Under the service contract, it is not anticipated that the Gabonese government will take physical delivery of its allocated production. Instead, the Company is authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government.

The Mutamba Iroru production sharing contract entitles the Company to receive 70% of any future production remaining after deducting the royalty so long as there are amounts remaining in the Cost Account. At December 31, 2014 there was $36.4 million in the Cost Account. As payment of corporate income taxes the consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 50% to 63% of the oil remaining after deducting the royalty and the cost oil. The percentage of "profit oil" paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, the Company only recovers ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. The Mutamba Iroru service contract provides for all commercial discoveries to be reclassified into a development area with a term of twenty years. At December 31, 2014, the Company has no proved reserves related to the Mutamba Iroru block.

The Block 5 production sharing contract in Angola entitles the Company to receive 50% of the any future production so long as there are amounts remaining in the Cost Account. There are no royalty payments under the contract. The consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 30% to 90% of the oil remaining after deducting the cost oil. The percentage of "profit oil" paid to the government as tax is a function of the Company's rate of return for each development area. The Block 5 production sharing contract provides for a discovery to be reclassified into a development area with a term of 20 years. At December 31, 2014, the Company has no proved reserves related to Block 5 in Angola.

The Block P production sharing contract in Equatorial Guinea entitles the Company to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 10% to 60% of the oil remaining after deducting the royalty and cost oil. The percentage of "profit oil" paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P production sharing contract provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2014, the Company has no proved reserves related to Block P in Equatorial Guinea.

SCHEDULE I — PARENT COMPANY FINANCIAL STATEMENTS

VAALCO ENERGY, INC.

UNCONSOLIDATED BALANCE SHEETS

(in thousands of dollars, except number of shares and par value amounts)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,780	$ 8,605
Restricted cash	-	10,000
Receivables:		
Other	264	7
Prepayments and other	505	89
Total current assets	4,549	18,701
Property and equipment - successful efforts method:		
Equipment and other	1,316	500
	1,316	500
Accumulated depreciation, depletion and amortization	(442)	(348)
Net property and equipment	874	152
Other assets:		
Restricted cash	10,000	-
Deferred tax asset	1,349	1,349
Investment in Subsidiaries	166,232	233,061
Total Assets	$ 183,004	$ 253,263
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	2,541	2,389

Total current liabilities	$	2,541		$	2,389	
Long term debt		-			-	
Total liabilities		2,541			2,389	
Minority Interest						
VAALCO Energy Inc. shareholders' equity:						
Common stock, $0.10 par value, 100,000,000 authorized shares, 65,194,828 and 64,012,914 shares issued with 7,393,714 and 7,162,573 shares in treasury at Dec. 31, 2014 and 2013, respectively		6,519			6,408	
Additional paid-in capital		64,351			55,455	
Retained earnings		146,892			224,442	
Less treasury stock, at cost		(37,299	)		(35,431	)
Total Equity		180,463			250,874	
Total Liabililities and Equity	$	183,004		$	253,263	

S-1

VAALCO ENERGY, INC.

STATEMENTS OF UNCONSOLIDATED OPERATIONS

(in thousands of dollars, except per share amounts)

	Year Ended December 31,		
	2014	2013	2012
Revenues:			
Oil and gas sales	$-	$-	$-
Operating costs and expenses:			
Depreciation, depletion and amortization	94	63	59
General and administrative expense	6,740	5,750	8,065
Total operating costs and expenses	6,834	5,813	8,124
Operating income (loss)	(6,834)	(5,813)	(8,124)
Other income (expense):			
Interest income	33	33	86
Other, net	450	-	-
Equity in subsidiary earnings	(71,199)	48,852	13,377
Total other income (expense)	(70,716)	48,885	13,463
Income (loss) before income taxes	(77,550)	43,072	5,339
Income tax expense	-	-	-
Net income (loss)	(77,550)	43,072	5,339
Less net income (loss) attributable to noncontrolling interest	-	-	(4,708)
Net income (loss) attributable to VAALCO Energy, Inc.	$(77,550)	$43,072	$631

S-2

VAALCO ENERGY, INC.

STATEMENTS OF UNCONSOLIDATED CASH FLOWS

(in thousands of dollars)

	Year Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$(77,550)	$43,072	$5,339
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	94	63	59
Stock based compensation	3,322	3,005	2,406
Equity in (earnings) loss from subsidiaries	71,199	(48,852)	(13,377)
Change in operating assets and liabilities:			
Other receivables	(257)	180	27
Prepayments and other	(416)	(16)	14
Accounts payable and other liabilities	153	371	(2,710)
Net cash (used in) operating activities	(3,455)	(2,177)	(8,242)
CASH FLOWS FROM INVESTING ACTIVITIES			
Investment in subsidiaries	(4,371)	(8,245)	-
Return of investment in subsidiaries	-	-	19,307
Decrease/(increase) in restricted cash	-	-	(10,000)
Property and equipment expenditures	(816)	(47)	(77)
Net cash (used in) investing activities	(5,187)	(8,292)	9,230
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of common stock	5,685	3,729	3,335
Purchase of treasury stock	(1,868)	(11,456)	-
Distribution to noncontrolling interest	-	-	(5,595)
Acquisition of noncontrolling interest	-	-	(26,200)
Net cash provided by (used in) financing activities	3,817	(7,727)	(28,460)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(4,825)	(18,196)	(27,472)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	8,605	26,801	54,273
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$3,780	$8,605	$26,801

Note 1- The financial statements of VAALCO Energy, Inc (the “Registrant” or “Parent Company”) have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended, because certain of VAALCO’s subsidiaries are contractually prohibited from making payments, loans or transferring assets to the Parent Company or other affiliated entities. Specifically, under the terms of our IFC credit facility, VAALCO Etame (Gabon), Inc. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the credit facility. The restricted net assets associated with each of these entities exceed 25% of the consolidated net assets of VAALCO Energy, Inc. as of December 31, 2014.

For purposes of these financial statements, the Parent Company’s investments in wholly owned subsidiaries are accounted for under the equity method. Under this method, the accounts of the subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded in the unconsolidated balance sheets. The income (loss) from operations of subsidiaries is reported on an equity basis as equity in subsidiary earnings, net of tax, in the unconsolidated statements of operations of registrant. These statements should be read in conjunction with the consolidated financial statements and notes thereto, included in Part II, Item 8 of in this Annual Report on Form 10-K.