UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

☒ **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: 001-12697

BPZ Resources, Inc.
(Exact name of registrant as specified in its charter)

Texas	**33-0502730**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification Number)

580 Westlake Park Blvd., Suite 525
Houston, Texas 77079
(Address of principal executive office)

Registrant's telephone number, including area code: **(281) 556-6200**

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, no par value	New York Stock Exchange

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

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

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

Note — Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Exchange Act from their obligations under those Sections.

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12-months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☐	Accelerated filer ☒
Non-Accelerated filer ☐	Smaller reporting company ☐

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

The number of shares of Common Stock held by non-affiliates as of June 30, 2014 was 67,603,654 shares, all of one class of common stock, no par value, having an aggregate market value of approximately $208,219,254 based upon the closing price of registrant's common stock on such date of $3.08 per share as quoted on the New York Stock Exchange. For purposes of the foregoing calculation, all directors, executive officers, and 5% beneficial owners have been deemed affiliated.

As of February 28, 2015 there were 118,663,085 shares of common stock, no par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

(1) Information required by Part III is incorporated by reference from Registrant's proxy statement or an amendment to this Annual Report on Form 10-K, which will be filed with the Securities and Exchange Commission within 120 days after the end of its fiscal year ended December 31, 2014.

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PART I

BPZ Resources, Inc. cautions that this document contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in or incorporated by reference into this Form 10-K which address activities, events or developments which the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. The words “may,” “will,” “should,” “could,” would,” “expects,” “plans,” “anticipates,” “intends,” “believes,” “estimates,” “projects,” “predicts,” “potential” and similar expressions are also intended to identify forward-looking statements.

These statements are based on certain assumptions and analyses made by the management of BPZ in light of its experience and its perception of historical trends, current conditions and expected future developments, as well as other factors it believes are appropriate under the circumstances. The Company cautions the reader that these forward-looking statements are subject to risks and uncertainties, many of which are beyond its control, that could cause actual events or results to differ materially from those expressed or implied by the statements. See Item 1A. — "Risk Factors" included in this Form 10-K.

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "BPZ" "we", "us", "our" and the "Company" refer to BPZ Resources, Inc., and its consolidated subsidiaries. References herein to "Debtor" refer only to BPZ Resources, Inc.

ITEM 1. BUSINESS

Introduction

BPZ Resources, Inc., a Texas corporation, is based in Houston, Texas with offices in Victoria, Texas, Lima and Zorritos, Peru and Quito, Ecuador. We are focused on the exploration, development and production of oil and natural gas in Peru and to a lesser extent Ecuador. We also intend to utilize part of our planned future natural gas production as a supply source for the development of a gas-fired power generation facility in Peru, which may be wholly-owned or partially-owned, or may be wholly-owned by a third party.

We maintain a subsidiary, BPZ Exploración & Producción S.R.L. ("BPZ E&P"), registered in Peru through our wholly-owned subsidiary BPZ Energy International Holdings, L.P., a British Virgin Islands limited partnership, and its subsidiary BPZ Energy, LLC, a Texas limited liability company. Currently, we, through BPZ E&P, have license agreements for oil and gas exploration and production covering a total of approximately 2.2 million gross (1.9 million net) acres, in four blocks, in northwest Peru and off the northwest coast of Peru in the Gulf of Guayaquil. Our license contracts cover ownership of the following properties: 51% working interest in Block Z-1 (0.6 million gross acres), 100% working interest in Block XIX (0.5 million gross acres), 100% working interest in Block XXII (0.9 million gross acres) and 100% working interest in Block XXIII (0.2 million gross acres). The Block Z-1 contract was signed in November 2001, the Block XIX contract was signed in December 2003 and the Blocks XXII and XXIII contracts were signed in November 2007. Generally, according to the Organic Hydrocarbon Law No. 26221 and the regulations thereunder (the "Organic Hydrocarbon Law" or "Hydrocarbon Law"), the seven-year term for the exploration phase can be extended in each contract by an additional three years up to a maximum of ten years. However, this exploration extension is subject to government approval and specific provisions of each license contract can vary the exploration phase of the contract as established by the Hydrocarbon Law. The license contracts require us to conduct specified activities in the respective blocks during each exploration period in the exploration phase. If the exploration activities are successful, we may decide to enter the exploitation phase and our total contract term can extend up to 30 years for oil production and up to 40 years for gas production. In the event a block contains both oil and gas, as is the case in our Block Z-1, the 40-year term may apply to oil production as well. Our estimate of proved reserves has been prepared under the assumption that our license contract will allow production for the possible 40-year term for both oil and gas.

We own a 10% non-operating net profits interest in an oil and gas producing property, Block 2, located in the southwest region of Ecuador (the "Santa Elena Property"). In May 2013, the license agreement and operating agreement covering the property were extended from May 2016 through December 2029.

Voluntary Reorganization Under Chapter 11

We have not been profitable since we commenced operations and we require substantial capital expenditures as we advance development projects at Block Z-1 and exploration projects in our other Blocks. Currently, we require additional financing to continue to fund our capital expenditure program and implement our business plan. Our major sources of funding to date have been oil sales, equity and debt financing activities and asset sales. The increased capital costs and debt service costs in the current economic environment for the oil and gas industry have placed a strain on our cash flow from operations and our ability to reduce our debt leverage.

We currently have the following convertible notes outstanding: (i) $59.9 million principal amount of Convertible Notes due 2015 (the “2015 Convertible Notes”), which bear interest semi-annually at a rate of 6.50% per year, and (ii) $168.7 million principal amount of Convertible Notes due 2017 (the “2017 Convertible Notes”), which bear interest semi-annually at a rate of 8.50% per year. The 2015 Convertible Notes matured with repayment of approximately $62 million in principal and interest due on March 1, 2015. Our estimated capital and exploratory budget for 2015 calls for us to spend approximately $58.6 million in 2015 on capital and exploratory expenditures, excluding capitalized interest, for our three onshore Blocks in which we hold 100% working interests, and our share of the capital and exploratory expenditures for offshore Block Z-1 required under our Joint Venture Agreement with Pacific Rubiales. The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014 and we are now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

The price of oil per barrel has dropped dramatically, particularly in the fourth quarter 2014 and continuing in the first quarter 2015, by more than half since its high in June 2014. In mid-October 2014, we withdrew our previously announced private placement offer of $150.0 million in senior secured notes due 2019 due to adverse market conditions.

On December 8, 2014, the Company received a notification from the New York Stock Exchange (“NYSE”) that the Company had fallen below the NYSE's continued listing standard relating to minimum share price, which requires a minimum average closing price of $1.00 per share over 30 consecutive trading days. The price has remained well below such threshold and the NYSE subsequently notified us on March 2, 2015 that it had determined to commence proceedings to delist our common stock.

As a result of the aforementioned events and circumstances, in December 2014 we engaged the services of Houlihan Lokey Capital Inc. (the “Advisors”) to assist us in analyzing various strategic alternatives and addressing our liquidity and capital structure, and formed a special committee of the Board of Directors to work with the Advisors. We engaged in discussions with representatives of our various debt holders regarding, among other items, the potential terms under which one or both bond issues could be restructured to provide a capital structure which would allow us to continue developing our oil and gas assets. We have also pursued discussions with other potential investors regarding alternative financing solutions. We decided that it was in the best long-term interest of all stakeholders, both credit and equity holders, to expeditiously address the Company's capital structure with the goal of reducing debt and the cost of capital to position the Company for the future, and on March 2, 2015 announced that we had decided not to pay approximately $62 million in principal and interest due on March 1, 2015 on our 2015 Convertible Notes and to use a 10-day grace period on principal due and a 30-day grace period on interest due to continue discussions with our debt holders.

We were unable to reach a mutually agreeable solution within the grace period for the principal amount due on the 2015 Convertible Notes and elected not to make the approximate $59.9 million in principal payment due at the end of the grace period for principal due. As a result, we are in default under the 2015 Convertible Notes, permitting the trustee for the 2015 Convertible Notes or the holders of at least 25% in aggregate principal amount of the outstanding 2015 Convertible Notes to declare the full amount of the principal and interest thereunder immediately due and payable. If the 2015 Convertible Notes were to be accelerated, an event of default would occur under the indenture for the 2017 Convertible Notes, permitting the trustee or the holders of at least 25% in aggregate principal amount of the outstanding 2017 Convertible Notes to also declare the full amount of the principal and interest thereunder immediately due and payable.

On March 9, 2015 (the “Petition Date”), BPZ Resources, Inc. (the “Debtor”) filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the “Bankruptcy Court”) to provide more time to find an appropriate solution to its financial situation and implement a plan of reorganization aimed at improving its capital structure. The Chapter 11 case is being administered by the Bankruptcy Court as Case No. 15-60016.

The filing of the Chapter 11 case constituted an event of default that triggered repayment obligations under the 2015 Convertible Notes and the 2017 Convertible Notes. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 case, and the creditors’ rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

Since the Petition Date, the Debtor has operated its business as a “debtor-in-possession” pursuant to Sections 1107(a) and 1108 of the Bankruptcy Code, which will allow the Debtor to continue operations during the reorganization proceedings. The Debtor will remain in possession of its assets and properties, and its business and affairs will continue to be managed by its directors and officers, subject in each case to the supervision of the Bankruptcy Court.

None of the Debtor’s direct or indirect subsidiaries or affiliates has filed for reorganization under Chapter 11 and none is expected to file for reorganization or protection from creditors under any insolvency or similar law in the U.S. or elsewhere. The Debtor’s subsidiaries will continue to operate outside of any reorganization proceedings. We therefore do not expect the Debtor’s filing for Chapter 11 protection to impact our license agreements.

On the day after the Petition Date, the Debtor obtained approval from the Bankruptcy Court for a variety of "first day" motions to give the Debtor the authority to take a broad range of actions, including, among others, authority to maintain bank accounts and the cash management system, pay certain employee obligations, post-petition utilities and other customary relief.

Overview

We are in the process of developing our Peruvian oil and gas reserves. We entered commercial production for Block Z-1 in November 2010 and produce and sell oil from the Corvina and Albacora fields under our current sales contracts. We completed the installation and permitting of the CX-15 platform in the Corvina field in November 2012 to continue the development of the field. In July 2013, we spudded the first development well from the CX-15 platform and have since completed drilling seven wells from the CX-15 platform. We also spudded a new development well from the A platform in the Albacora field of Block Z-1 in September 2013 and have completed drilling four wells thereafter from the A platform. From the time we began producing from the Corvina field in November 2007 and the Albacora field in December 2009, through December 31, 2014, the two fields have produced approximately 7.4 MMBbls (100% gross and net through December 14, 2012 and 51% net thereafter) of oil. Three onshore shallow exploration wells, ranging in depth from 3,500 to 3,800 feet, have been drilled at Block XXIII during 2014. We are planning to pursue a long term testing program in these Block XXIII prospects, starting with Piedra Candela, and potentially sell the tested gas under a pilot program to the local communities.

On December 14, 2012 Perupetro S.A. ("Perupetro"), a corporation owned by the Peruvian government empowered to become a party in the contracts for the exploration and/or exploitation of hydrocarbons in order to promote these activities in Peru, approved the terms of the amendment to the Block Z-1 License Contract to recognize the sale of a 49% participating interest ("closing"), in offshore Block Z-1 to Pacific Rubiales Energy Corp. ("Pacific Rubiales"). Under terms of the agreements signed on April 27, 2012, we (together with our subsidiaries) formed an unincorporated joint venture with a Pacific Rubiales subsidiary, Pacific Stratus Energy S.A., to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the agreements, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of our share of capital and exploratory expenditures in Block Z-1 ("carry amount") from the effective date of the Stock Purchase Agreement ("SPA"), January 1, 2012. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

The development of Block Z-1 is subject to the terms and conditions of a Joint Operating Agreement with Pacific Rubiales that governs the legal, technical and operating rights and obligations of the parties with respect to the operation of Block Z-1. Under the agreement, we are the operator and responsible for the administrative, regulatory, government and community related duties, and Pacific Rubiales manages the technical and operating duties in Block Z-1. The Joint Operating Agreement will continue for the term of the Block Z-1 License Contract and thereafter until all decommissioning obligations under the License Contract have been satisfied.

At December 31, 2014, we had estimated net proved oil reserves of 13.6 MMBbls, of which 9.8 MMBbls were in the Corvina field and 3.8 MMBbls were from the Albacora field. Both fields are located in Block Z-1 offshore of northwest Peru. Of our total proved reserves, 4.2 MMBbls (30.9%) are classified as proved developed reserves consisting of proved developed producing and proved developed non-producing reserves from 22 gross (11.2 net) wells, and 9.4 MMBbls (69.1%) are classified as proved undeveloped reserves. The process of estimating oil and natural gas reserves is complex and requires many assumptions that may turn out to be inaccurate. See Item 1A - "Risk Factors" for further information.

We have determined our reporting structure provides for only one operating segment as we only operate in Peru and currently have only one customer for our production. Information regarding our operating segment, including our revenues and long-lived assets can be found in the footnotes to our consolidated financial statements in Item 8 – "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Our Business Plan

Our business plan is to enhance value through application of our knowledge of our targeted areas in Peru and to leverage management's experience with the local suppliers and regulatory authorities to effectively and efficiently (i) identify and quantify the potential value of our oil and gas holdings in Peru; (ii) develop and increase production and cash flows from our identified holdings; (iii) create an additional revenue stream through implementation of our gas marketing strategy and (iv) bring working interest partners into some or all of our Peruvian blocks to facilitate the exploration and development of these blocks.

Our focus is to reappraise and develop properties that we control under license agreements in northwest Peru that have been explored by other companies that have reservoirs that appear to contain commercially productive quantities of oil and gas, as well as other areas that have geological formations that we believe potentially contain commercial amounts of hydrocarbons.

Our management team has extensive engineering, geological, geophysical, technical and operational experience and valuable knowledge of oil and gas operations throughout Latin America and, in particular, Peru.

Two of the four blocks (Block Z-1 and Block XXIII) contain structures drilled by previous operators who encountered hydrocarbons. However, at the time the wells were drilled, the operators did not consider it economically feasible to produce those hydrocarbons. Having tested oil in Block Z-1 in our first well in the Corvina field in 2007 and our first well in Albacora in December 2009, we are focusing on development of the proved oil reserves in those two fields. Before considering further drilling activity in Block XIX, we are planning to acquire additional seismic data. In Block XXII, the process for an environmental permit is underway and approval must be received before anticipated drilling can begin in 2016. Three onshore shallow exploration wells, ranging in depth from 3,500 to 3,800 feet, have been drilled at Block XXIII during 2014. These wells targeted the Caracol, El Cardo, and Piedra Candela prospects, which are on a six-mile trend. All three wells tested dry gas from the Mancora formation.

In the near term, management is focused on drilling operations at both the CX-15 platform in the Corvina field and at the A platform in the Albacora field, utilizing the results of the 1,600 square kilometers ("km") of three dimensional ("3-D") seismic survey in Block Z-1. We plan to pursue a long-term testing program in the Block XXIII prospects and are in preliminary discussions with a local compressed natural gas (CNG) distributor to purchase the gas produced as a result of the long-term testing program. Additional appraisal wells could be included in the long-term testing program if test results warrant. We have received the long-term gas testing permit.

In addition, our business plan includes a gas-to-power project as part of our overall gas marketing strategy, which entails the installation of a 10-mile gas pipeline from the CX-11 platform to shore, the construction of gas processing facilities and the building of an approximately 135 megawatt ("MW") simple cycle electric generating plant. The proposed power plant site is located adjacent to an existing substation and power transmission lines which, with certain upgrades, are expected to be capable of handling up to 420 MW of power. The power generation facility may be wholly or partially owned by us, or wholly owned by a third party. The gas-to-power project is planned to generate a revenue stream by creating a market for the non-associated gas in our Corvina field that is currently shut-in. This project has not yet been financed and we continue to consider the alternatives for the project. Meanwhile, we have obtained certain permits and are in the process of obtaining additional permits to proceed with the project.

Available Information

We file annual, quarterly and periodic reports, proxy statements and other information with the Securities and Exchange Commission (the "SEC" or the "Commission") in accordance with the Securities Exchange Act of 1934. You may read and copy this information at 100 F Street, N.E., Room 1580, Washington, D.C. 20549.

You can also obtain copies of such material from the Public Reference Section of the SEC, 100 F Street, N.E., Room 1580, Washington, D.C. 20549 at prescribed rates. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with it, like BPZ Resources, Inc. The SEC's website can be accessed at http://www.sec.gov.

In addition, we maintain a website (www.bpzenergy.com) on which we also make available, free of charge, all of our above mentioned SEC filings, including Forms 3, 4 and 5 filed with respect to our equity securities under Section 16(a) of the Securities Act of 1934. These filings will be available as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Our Competition

The oil and gas industry can be highly competitive and we compete with numerous other companies. Our competitors in the exploration, development acquisition and production business include major integrated oil and gas companies as well as numerous independent companies, including many that have significantly greater financial resources. Many major and independent oil and gas companies actively pursue and bid for the mineral rights of desirable properties, and many companies have been actively engaged in acquiring oil and gas properties, specifically in Peru and Ecuador.

We believe our efforts in and knowledge of our targeted areas has given us a competitive advantage in Peru, and to a lesser extent, Ecuador. Although un-licensed tracts exist within our target area of Northwest Peru, the majority of our target areas are located within our Blocks. Any increased demand for license contracts in surrounding areas may impact our ability to expand and grow in the future, particularly because many of our competitors have substantially greater financial and other resources, in addition to better name recognition and longer operating histories.

Any increased demand for oil and gas impacts the competition for access to drilling and other contract services and experienced technical and operating personnel needed to drill and complete wells. Competition for drilling and contract services in our target area exists and may affect our plan of operation. In addition, because we operate in a remote area of Peru, the limited availability of equipment could impact our operations or the cost of our operations. We continually monitor our operating plans and timelines to adapt to this dynamic environment. However, any limitations on availability of drillers and contractors may limit our ability to execute in a timely manner and may negatively impact our ability to grow.

Customers

To date, all of our sales of oil in Peru have been made under contracts with the Peruvian national oil company, Petroleos del Peru - PETROPERU S.A. (“Petroperu”). However, we believe that the loss of our sole customer would not materially impact our business because we could readily find other purchasers for our oil production both in Peru and elsewhere in the world.

Regulation Impacting Our Business

General

Various aspects of our oil and natural gas operations are currently or will be subject to various foreign laws and governmental regulations. These regulations may be changed from time to time in response to economic or political conditions.

Peru

Peruvian hydrocarbon legislation. Peru’s hydrocarbon legislation, which includes the Organic Hydrocarbon Law, governs our operations in Peru. This legislation covers the entire range of petroleum operations, defines the roles of Peruvian government agencies and related authorities which regulate and interact with the oil and gas industry, requires that investments in the petroleum sector be undertaken solely by private investors (either national or foreign), and provides for the promotion of the development of hydrocarbon activities based on free competition and free access to all economic activities. This regulation provides that pipeline transportation and natural gas distribution must be handled via contracts with the appropriate governmental authorities.

Under this legal system, Peru is the owner of the hydrocarbons located below the surface in its national territory. However, Peru has given the right to extract hydrocarbons to Perupetro. The Peruvian government also plays an active role in petroleum operations through the involvement of the Ministry of Energy and Mines (“MEM”), which is the body of the executive branch of the Peruvian government in charge of devising energy, mining and environmental protection policies, enacting the rules applicable to these sectors and supervising compliance with such policies and rules. The General Directorate of Hydrocarbons (“DGH”) is the agency of the Ministry of Energy and Mines responsible for regulating the optimum development of oil and gas fields and the Direccion General de Asuntos Ambientales Energeticos (“DGAAE”) is the agency of the Ministry of Energy and Mines responsible for reviewing and approving environmental regulations related to environment risks that result from hydrocarbon exploration and exploitation activities. The Environmental Evaluation and Fiscalization Entity (“OEFA”) is the agency within the Ministry of the Environment that is responsible for evaluating and ensuring compliance with applicable environmental rules covering hydrocarbon activities, and for sanctioning non-compliant companies. The General Directorate of Mining and the Organismo Supervisor de la Inversión en Energía y Mineria (“OSINERGMIN”), an entity of the Ministry of the President, are responsible for ensuring compliance with occupational health and safety standards in the hydrocarbon industry. We are subject to the laws and regulations of all of these entities and agencies, as well as the Ministry of Agriculture, the Ministry of Culture and the Dirección General de Capitanías y Guardacostas del Perú (“DICAPI”).

Perupetro generally enters into either license contracts or service contracts for hydrocarbon exploration and exploitation. Peru’s laws also allow for other contract models, but the models must be authorized by the Ministry of Energy and Mines. We only operate under license contracts and do not foresee operating under any services contracts in the immediate future. A company must be qualified by Perupetro to enter into hydrocarbon exploration and exploitation contracts in Peru. In order to qualify, the company must meet the standards under the Regulations Governing the Qualifications of Oil Companies. These qualifications generally require the company to have the technical, legal, economic and financial capacity to comply with all obligations it will assume under the contract. These requirements will depend on the characteristics of the area requested, the possible investments and the environmental protection rules governing the performance of its operations. When a contractor is a foreign investor, it is expected to incorporate a subsidiary company or registered branch in accordance with Peru’s laws and appoint local representatives who will interact with Perupetro.

Perupetro reviews a company’s qualification for each license contract to be signed by a company. Additionally, the qualification for foreign companies is granted in favor of the home office, in our case BPZ Resources, Inc., which provides a corporate guarantee to Perupetro. The corporate guarantee provides for joint and several liability to Perupetro with respect to the fulfillment of each minimum work program of the contract. BPZ Resources, Inc. and its corresponding subsidiary in Peru have been qualified by Perupetro with respect to our current contracts as required by regulation.

When operating under a license contract, the licensee is the owner of the hydrocarbons extracted from the contract area once the corresponding royalty has been paid to Perupetro. The licensee can market the hydrocarbons in any manner whatsoever and can fix hydrocarbon sales prices according to market forces, subject to a limitation in the case of natural emergencies, in which case the law stipulates such manner of marketing.

Licensees are obligated to submit quarterly reports to the DGH. Licensees must also submit a monthly economic report to the Central Reserve of Peru (“Banco Central de Reserva”). These reports are generally combined and delivered together with other operating reports required to be submitted to Perupetro.

The duration of the license contracts is based on the nature of the hydrocarbons discovered. The license contract duration for crude oil is 30 years, while the contract duration for natural gas and condensates is 40 years. In the event a block contains both oil and gas, as is the case in our Block Z-1, the 40-year term may apply to oil exploration and production as well. The license contract commences on an agreed date, the effective date, established in the license contract. Most contracts typically include an exploration phase and an exploitation phase, unless the contract is solely an exploitation contract. Within the contract term, seven years is allotted to exploration, with the possibility of an extension of up to three years, granted at the discretion of Perupetro. A potential deferment period for a maximum of ten years is also available if certain factors recognized by law delay the economic viability of a discovery, such as a lack of transportation facilities or a lack of a market. The exploration phase is generally divided into several periods and each period includes a minimum work program. The term of the exploration phase may last longer than the prescribed seven years, or ten years if the three-year extension was granted, as the time elapsed for the approval of the respective environmental permits is not taken into consideration as part of the respective exploration period. However, the term of the license contract stays the same. The fulfillment of the minimum work program must be supported by an irrevocable bank guaranty, usually in the amount of fifty percent of the estimated value of the minimum work program.

We currently have four license contracts. As of March 16, 2015, we believe we are in compliance with all of the material requirements of each contract. We have executed certain letters of guaranty in favor of Perupetro to insure our performance under the license contracts. At December 31, 2014, we had $5.7 million in bonds posted at various dates to secure our obligation under the license contracts for Blocks XIX, XXII, XXIII and Z-1. The license contract bonds are partially secured by the deposit of restricted cash in the amount of $1.6 million with the financial institutions which issued the bonds. Should we fail to fulfill our minimum work program obligations under any of our license contracts without technical justification or other good cause, Perupetro could seek recourse to the bond or terminate the license contract. Additionally, we have $0.6 million of restricted cash for performance of work related to construction of our gas-to-power project.

Legislation in Peru was passed by Supreme Decree 088-2009 on December 13, 2009 with respect to regulating well testing and gas flaring. The legislation provides that all new wells may be properly placed on production testing for up to six months. If the operator believes a longer period for testing the well is needed to evaluate the productive capacity of the field, the legislation provides a process by which an operator can request an extension to allow for additional testing – extended well testing ("EWT"). After the initial six-month period or after an EWT program expires, the operator will be required to have the necessary gas and water reinjection equipment in place to continue operating the well according to existing environmental regulations.

Peruvian fiscal regime. Peru's fiscal regime determines the government's entitlement from petroleum activities. This regime is subject to change, which could negatively impact our business. However, the Organic Hydrocarbon Law and the Regulations Governing the Tax Stability Guaranty and Other Tax Rules of the Organic Hydrocarbon Law provide that the tax regime in force on the date of signing a contract will remain unchanged during the term of the contract. Therefore, any change to the tax regime, which results in either an increase or decrease in the tax burden, will not affect the operator.

License contracts include royalty payment schemes, which are usually a fixed percentage of the actual production that is verified by Perupetro. The regulations stipulate a minimum royalty payment of five percent for production less than 5,000 Boepd, increasing incrementally to a maximum of twenty percent for production greater than 100,000 Boepd. However, when a company bids for a license contract on a new area it can elect to voluntarily increase the royalty percentage above the sliding scale rate in its bid to improve its chances of success. See Item 2. "Properties" for further information regarding royalties applicable to each Block.

During the exploration phase, operators are exempt from import duties and other forms of taxation applicable to goods intended for exploration activities. Exemptions are withdrawn at the production phase, but exceptions are made in certain instances, and the operator may be entitled to temporarily import goods tax-free for a two-year period ("Temporary Import"). Temporary Import may be extended for additional one year periods for up to two years upon operator request, approval of the MEM and authorization of the Superintendencia Nacional de Aduanas y de Administracion Tributaria (Peruvian Customs Agency).

Taxable income is determined by deducting allowable operating and administrative expenses, including royalty payments. Income tax is levied on the income of the operator based upon the legal corporate tax rate in effect at the date the license contract was signed. Operators engaged in the exploration and production of crude oil, natural gas and condensates must determine their taxable income separately for each license contract under which they operate. Where a contractor carries out these activities under different individual license contracts, it may offset its earnings before income tax under one license contract with losses under another license contract, for purposes of determining the corporate income tax, provided that the individual license contracts are held by the same company, as Peruvian tax law does not permit filing a consolidated tax return for related companies. However, under no circumstances can the investment in the producing property be amortized for tax purposes unless the company is under the commercial stage of production.

Peruvian labor and safety legislation. Our operations in Peru are also subject to the Labor Law, which governs the labor force in the petroleum sector. In addition, the Organic Hydrocarbon Law and related Safety Regulations for the Petroleum Industry also regulate the safety and health of workers involved in the development of hydrocarbon activities. All entities engaged in the performance of activities related to the petroleum industry must provide the General Hydrocarbons Bureau with the list of their personnel on a semi-annual basis, indicating their nationality, specialty and position. These entities must also train their workers on the application of safety measures in the operations and control of disasters and emergencies. The regulations also contain provisions on accident prevention and personnel health and safety, which in turn include rules on living conditions, sanitary facilities, water quality at workplaces, medical assistance and first-aid services. Provisions specifically related to the exploration phase are also contained in the regulations and include safety measures related to camps, medical assistance, food conditions, and handling of explosives. Additional safety regulations may also become applicable as we expand and develop our operations.

The Labor laws and regulations also define the employer/employee relationship. As such, employers can only terminate the employment relationship for just cause as established by Peruvian law. If an employee is terminated for any reason other than those listed in the Law on Productivity and Labor Competitiveness, the employer will be required to pay an indemnity to the employee for arbitrary dismissal (calculated according to the length of service), or may be required to reinstate the employee.

The Constitution of Peru and Legislative Decree Nos. 677 and 892 give employees working in private companies engaged in activities generating income, as defined by the Income Tax Law, the right to share in a company's profits. This profit sharing is carried out through the distribution by the company of a percentage of the annual income before tax. According to Article 3 of the United Nations International Standard Industrial Classification, BPZ Resources, Inc.'s tax category is classified under the "mining companies" section, which sets the rate at 8%. However, in Peru, the Hydrocarbons' Law states, and the Supreme Court ruled, that hydrocarbons are not related to mining activities. Hydrocarbons are included under "Companies Performing other Activities," and as a result, oil and gas companies pay profit sharing at a rate of 5%. The benefit granted by the law to employees is calculated on the basis of the "net income subject to taxation" and not on the net business or accounting income of companies. "Taxable income" is obtained after deducting from total revenues subject to income tax, the expenses required to produce them or maintain the source thereof.

Peruvian environmental regulation. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Peru has enacted specific environmental regulations applicable to the hydrocarbon industry. The Code on the Environment and the Natural Resources establishes a framework within which all specific laws and regulations applicable to each sector of the economy are to be developed. These laws and regulations are designed to ensure a continual balance of environmental and petroleum interests, and is therefore subject to change. The regulations stipulate certain environmental standards expected from contractors. They also specify appropriate sanctions to be enforced if a contractor fails to maintain such standards. The OEFA is the agency within the Ministry of the Environment that is responsible for evaluating and ensuring compliance with applicable environmental laws and regulations covering hydrocarbon activities, and for sanctioning non-compliant companies.

The Environmental Regulations for Hydrocarbon Activities provide that companies participating in the implementation of projects, performance of work and operation of facilities related to hydrocarbon activities are responsible for the emission, discharge and disposal of wastes into the environment. Companies file an annual report describing the company's compliance with the current environmental legislation.

Companies involved in hydrocarbon activities must also prepare and file an Environmental Impact Study ("EIS") or Environment Impact Assessment ("EIA") with the DGAAE, which is part of the Ministry of Energy and Mines, in order for a Company to demonstrate that its activities will not adversely affect the environment and to show compliance with the maximum permissible emission limits set forth by the Ministry of Energy and Mines. An EIS must be prepared for each project to be carried out. All of these proposals must be approved in advance by the DGAAE.

In May 2013, the Peruvian government enacted several Supreme Decrees that adopted special provisions to speed up administrative procedures, special provisions for the performance of administrative procedures and other measures to encourage private and public investment projects. These provisions establish reduced time periods for obtaining approvals to protect archaeological, water and other environmental resources, including approval of Environmental Impact Studies. These new measures are expected to speed up the hydrocarbon investments in the existing license contracts for the exploration and exploitation of hydrocarbons in Peru. We cannot, however, predict the actual effectiveness or benefits of these new measures.

In addition, any party responsible for hydrocarbon activities must file an "Oil Spill and Emergency Contingency Plan" with the General Hydrocarbons Bureau, which is part of the Ministry of Energy and Mines. The plan must be updated at least once a year and must contain information regarding the measures to be taken in the event of spills, explosions, fires, accidents, evacuation, etc.

Peru has enacted amendments to its environmental law, imposing restrictions on the use of natural resources, interference with the natural environment, location of facilities, handling and storage of hydrocarbons, use of radioactive material, disposal of waste, emission of noise and other activities. Additionally, the laws require monitoring and reporting obligations in the event of any spillage or unregulated discharge of hydrocarbons.

Any failure to comply with environmental protection laws and regulations, the import of contaminated products, or the failure to keep a monitoring register or send reports to the General Hydrocarbons Bureau in a timely fashion could subject the company responsible for non-compliance to fines. In addition, the General Hydrocarbons Bureau may consider imposing a prohibition or restriction of the relevant activity, an obligation to compensate the aggrieved parties and/or an obligation to immediately restore the area. The company responsible for any default may also be subject to a suspension of operations for a term of one, two or three months, or indefinitely. Furthermore, any contract entered into with the Peruvian government, the implementation of which jeopardizes or endangers the protection or conservation of protected natural areas, may be terminated.

We are subject to all present and future Peruvian environmental regulations applicable to the petroleum industry. For example, we are required to obtain an environmental permit or approval from the government in Peru prior to conducting any seismic operations, drilling a well or constructing a pipeline in Peruvian territory, including the waters offshore in Peru where we currently conduct oil and gas operations. As in many countries, there is an element of uncertainty in how Peruvian authorities will enforce and supervise environmental compliance and standards. Further, we cannot predict any future regulation or the cost associated with future compliance.

Peruvian electric power legislation. Our business plan envisions the sale of natural gas for power generation or the generation of electricity to monetize our natural gas and the sale of such electric power in Peru. The basic laws of Peru governing electric power, which will apply to our future operations, are the Law of Electric Power Concessions and the Regulations for the Environmental Protection of Electric Power Activities, and the corresponding regulations for each, as well as additional related laws and regulations, including all legislation regarding Electric Power Tariffs and all regulations and technical norms created by the National Commission of Electric Power Tariffs.

Compliance with Existing Legislation in Peru

Although we believe our operations are and will continue to be in substantial compliance with existing legislation and requirements of Peruvian governmental bodies, our ability to conduct continued operations is subject to satisfying applicable regulatory and permitting controls. Our management team has extensive experience in dealing directly with the Peruvian government on energy projects. Therefore, we believe we are in a good position to understand and comply with local rules and regulations. However, our current permits and authorizations as well as our ability to obtain future permits and authorizations may, over time, be susceptible to increased scrutiny and greater complexity which could result in increased costs or delays in receiving appropriate authorizations.

Ecuador

SMC Ecuador, Inc., our wholly-owned subsidiary, has held its 10% non-operating net profits interest in the Santa Elena oil fields since 1997. We acquired all of the common stock of SMC Ecuador Inc. in 2004. As a non-operator, we are not directly subject to the laws and regulations of Ecuador covering the oil and gas industry and the environment. However, if we begin operating activities in Ecuador, we will be directly subject to such laws and regulations.

Environmental Compliance and Risks

As a licensee and operator of oil and gas properties in South America, and in particular Peru, we are subject to various national, state and local laws and regulations relating to the discharge of materials into, and the protection of, the environment. These laws and regulations may, among other things, impose liability on the licensee under an oil and gas license agreement for the cost of pollution clean-up resulting from operations, subject the licensee to liability for pollution damages, and require suspension or cessation of operations in affected areas.

In addition to certain pollution coverage related to our surface facilities, we also maintain insurance coverage for seepage and pollution, cleanup and contamination from our wells. Regardless, no such coverage can insure us fully against all risks, including environmental risks. We are not aware of any environmental claims which would have a material impact upon our financial position or results of operations.

We will continue our efforts to comply with these requirements, which we believe are necessary to maintain successful long-term operations in the oil and gas industry. As part of this effort we have established guidelines for continuing compliance with environmental laws and regulations. In order to carry out our plan of operation, we are required to conduct environmental impact studies and obtain environmental approvals for operations. We have engaged outside consultants to perform these studies and assist us in obtaining necessary approvals. Our cost for these studies and assistance related to the Block Z-1, Block XIX, Block XXII and Block XXIII for the year ended December 31, 2014, 2013, and 2012 were approximately $0.8 million, $0.3 million, and $0.5 million, respectively.

We believe we are in compliance with national, state and local provisions regarding the regulation of discharge of materials into the environment, or otherwise relating to the protection of the environment. However, there is no assurance that changes in or additions to laws or regulations regarding the protection of the environment will not negatively impact our operations in the future.

Operational Hazards and Insurance

Our operations are subject to the usual hazards incidental to the drilling and production of oil and gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution, releases of toxic gas and other environmental hazards and risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations.

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because the costs are considered prohibitive. We currently have insurance coverage which we believe is adequate for our current stage of operations based on management's assessment. Such insurance may not cover every potential risk associated with the drilling, production and processing of oil and gas. In particular, coverage is not obtainable for all types of environmental hazards. Additionally, the occurrence of a significant adverse event, the risks of which are not fully covered by our insurance policy, could have a material adverse effect on our financial condition and results of operations. Moreover, no assurance can be given that we will be able to maintain adequate insurance or increase current coverage amounts at rates we consider reasonable.

Research and Development

We seek to use advanced technologies in the evaluation of our oil and gas properties and in evaluating new opportunities. We generally do not develop such technologies internally, but our technical team works with outside vendors to test and utilize these technologies to the fullest extent practical, particularly in the application of geophysical, geological and engineering software. We do not believe we have incurred any quantifiable incremental costs in connection with research and development.

Employees

As of December 31, 2014, we employed 25 full-time employees of BPZ Resources, Inc., and 75 full-time employees within our subsidiaries BPZ E&P and BPZ Marine Peru S.R.L.

We believe that our relationship with our employees is satisfactory. None of our employees are currently represented by a union.

ITEM 1A. RISK FACTORS

Risks Related to Bankruptcy.

BPZ Resources, Inc. (the "Debtor") filed for reorganization under Chapter 11 of the Bankruptcy Code on March 9, 2015 (the "Chapter 11 Case") and is subject to the risks and uncertainties associated with Chapter 11 cases. For the duration of the Chapter 11 Case, our operations and our ability to execute our business strategy will be subject to the risks and uncertainties associated with bankruptcy. These risks and uncertainties include:

- our ability to develop, prosecute, confirm and consummate a plan of reorganization with respect to the Chapter 11 Case;
- our ability to obtain Bankruptcy Court approval with respect to motions filed in the Chapter 11 Case from time to time;
- the actions and decisions of our creditors and other third parties who have interests in the Chapter 11 Case that may be inconsistent with our plans;
- the ability of third parties to seek and obtain court approval to terminate or shorten the exclusivity period for us to propose and confirm a plan of reorganization, to appoint a U.S. trustee or to convert the Chapter 11 Case to a Chapter 7 case;
- our ability to obtain and maintain normal payment and other terms with customers, vendors and service providers;
- our ability to maintain contracts that are critical to our operations;
- our ability to attract, motivate and retain key employees;
- our ability to retain key vendors or secure alternative supply sources;
- our ability to fund and execute our business plan;
- our ability to obtain acceptable and appropriate financing, including debtor-in-possession financing if required; and
- our ability to utilize net operating loss carryforwards.

These risks and uncertainties could affect our business and operations in various ways. For example, negative events or publicity associated with the Chapter 11 Case could adversely affect our relationships with our vendors and employees, as well as with customers, which in turn could adversely affect our operations and financial condition. Also, pursuant to the Bankruptcy Code, we need Bankruptcy Court approval for transactions outside the ordinary course of business, which may limit our ability to respond timely to events or take advantage of opportunities. Because of the risks and uncertainties associated with the Chapter 11 Case, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 proceedings will have on our business, financial condition and results of operations, and there is no certainty as to our ability to continue as a going concern. In addition, our auditors have expressed substantial doubt about our ability to continue as a going concern. See the Report of Independent Registered Public Accounting Firm included under Item 8. "Financial Statements and Supplementary Data."

As a result of the Chapter 11 Case, realization of assets and liquidation of liabilities are subject to uncertainty. While operating under the protection of the Bankruptcy Code, and subject to Bankruptcy Court, approval or otherwise as permitted in the normal course of business, we may sell or otherwise dispose of assets and liquidate or settle liabilities for amounts other than those reflected in our consolidated financial statements. Further, a plan of reorganization could materially change the amounts and classifications reported in our consolidated historical financial statements, which do not give effect to any adjustments to the carrying value of assets or amounts of liabilities that might be necessary as a consequence of confirmation of a plan of reorganization.

A plan of reorganization or liquidation may result in holders of our capital stock receiving very limited or no distribution on account of their interests and cancellation of their existing stock. If certain requirements of the Bankruptcy Code are met, a Chapter 11 plan or reorganization can be confirmed notwithstanding its rejection by our equity securityholders and notwithstanding the fact that such equity securityholders do not receive or retain any property on account of their equity interests under the plan.

Operating under Bankruptcy Court protection for a long period of time may harm our business. Our future results are dependent upon the successful confirmation and implementation of a plan of reorganization. A long period of operations under Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as the proceedings related to the Chapter 11 Case continue, our senior management will be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. A prolonged period of operating under Bankruptcy Court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, the longer the proceedings related to the Chapter 11 Case continue, the more likely it is that our customers and suppliers will lose confidence in our ability to reorganize our businesses successfully and will seek to establish alternative commercial relationships.

Furthermore, so long as the proceedings related to the Chapter 11 Case continue, we will be required to incur substantial costs for professional fees and other expenses associated with the administration of the Chapter 11 Case. The Chapter 11 Case filing will also likely require us to seek debtor-in-possession financing to fund operations. If we are unable to obtain such financing on favorable terms or at all, our chances of successfully reorganizing our business may be seriously jeopardized, the likelihood that we instead will be required to liquidate our assets may be enhanced, and, as a result, any securities in the Debtor could become further devalued or become worthless.

Furthermore, we cannot predict the ultimate amount of all settlement terms for the liabilities that will be subject to a plan of reorganization. Even once a plan of reorganization is approved and implemented, our operating results may be adversely affected by the possible reluctance of prospective lenders to do business with a company that recently emerged from Chapter 11 proceedings.

We may not be able to obtain confirmation of a Chapter 11 Plan of Reorganization. To emerge successfully from Bankruptcy Court protection as a viable entity, we must meet certain statutory requirements with respect to adequacy of disclosure with respect to a Chapter 11 plan of reorganization, solicit and obtain the requisite acceptances of such a plan and fulfill other statutory conditions for confirmation of such a plan, which have not occurred to date. The confirmation process is subject to numerous, unanticipated potential delays, including a delay in the Bankruptcy Court's commencement of the confirmation hearing regarding our plan.

We may not receive the requisite acceptances of constituencies in the proceedings related to the Chapter 11 Case to confirm our Plan. Even if the requisite acceptances of our Plan are received, the Bankruptcy Court may not confirm such a plan. The precise requirements and evidentiary showing for confirming a plan, notwithstanding its rejection by one or more impaired classes of claims or equity interests, depends upon a number of factors including, without limitation, the status and seniority of the claims or equity interests in the rejecting class (i.e., secured claims or unsecured claims, subordinated or senior claims, preferred or common stock).

If a Chapter 11 plan of reorganization is not confirmed by the Bankruptcy Court, it is unclear whether we would be able to reorganize our business and what, if anything, holders of claims against us would ultimately receive with respect to their claims.

We may be subject to claims that will not be discharged in the Chapter 11 Case, which could have a material adverse effect on our results of operations and profitability. The Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation and specified debts arising afterwards. With few exceptions, all claims that arose prior to March 9, 2015 and before confirmation of a plan of reorganization (i) would be subject to compromise or treatment under the plan of reorganization or (ii) would be discharged in accordance with the Bankruptcy Code and the terms of the plan of reorganization. Any claims not ultimately discharged by the Bankruptcy Court could have an adverse effect on our results of operations and profitability.

Even if a Chapter 11 Plan of Reorganization is consummated, we will continue to face risks. Even if a Chapter 11 plan of reorganization is consummated, we will continue to face a number of risks, including certain risks that are beyond our control, such as further deterioration or other changes in economic conditions, changes in our industry, potential revaluing of our assets due to Chapter 11 proceedings, changes in consumer demand for, and acceptance of, our oil and gas and increasing expenses. Some of these concerns and effects typically become more acute when a case under the Bankruptcy Code continues for a protracted period without indication of how or when the case may be completed. As a result of these risks and others, there is no guaranty that a Chapter 11 plan of reorganization reflecting the Plan will achieve our stated goals.

In addition, at the outset of the Chapter 11 Case, the Bankruptcy Code gives the Debtor the exclusive right to propose the Plan and prohibited creditors, equity security holders and others from proposing a plan. We have currently retained the exclusive right to propose the Plan. If the Bankruptcy Court terminates that right, however, or the exclusivity period expires, there could be a material adverse effect on our ability to achieve confirmation of the Plan in order to achieve our stated goals.

Furthermore, even if our debts are reduced or discharged through the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the completion of the proceedings related to the Chapter 11 Case. Adequate funds may not be available when needed or may not be available on favorable terms.

Transfers of our equity, or issuances of equity in connection with our restructuring, may impair our ability to utilize our federal income tax net operating loss carryforwards in the future. Under federal income tax law, a corporation is generally permitted to deduct from taxable income in any year net operating losses carried forward from prior years. We have net operating loss carryforwards related to the Debtor of approximately $163.0 million as of December 31, 2014. Our ability to deduct net operating loss carryforwards will be subject to a significant limitation if we were to undergo an “ownership change” for purposes of Section 382 of the Internal Revenue Code of 1986, as amended, during or as a result of our Chapter 11 proceedings and we are unable to qualify for the exception to the carryforward limit for corporations that have changed ownership under a Chapter 11 plan. Our ability to deduct net operating loss carryforwards would be reduced by the amount of any cancellation of debt income resulting from the proposed restructuring that is allocable to the Debtor.

Our financial results may be volatile and may not reflect historical trends. While in bankruptcy, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities, contract terminations and rejections, and claims assessments may significantly impact our consolidated financial statements. As a result, our historical financial performance is likely not indicative of our financial performance after the date of the filing of the Chapter 11 Case. In addition, if we emerge from bankruptcy, the amounts reported in subsequent consolidated financial statements may materially change relative to historical consolidated financial statements, including as a result of revisions to our operating plans pursuant to a plan of reorganization. In addition, if we emerge from bankruptcy, we may be required to adopt fresh start accounting. If fresh start accounting is applicable, our assets and liabilities will be recorded at fair value as of the fresh start reporting date. The fair value of our assets and liabilities may differ materially from the recorded values of assets and liabilities on our consolidated balance sheets. In addition, if fresh start accounting is required, our financial results after the application of fresh start accounting may be different from historical trends.

Our successful reorganization will depend on our ability to motivate key employees and successfully implement new strategies. Our success is largely dependent on the skills, experience and efforts of our people. In particular, the successful implementation of our business plan and our ability to successfully consummate a plan of reorganization will be highly dependent upon our management. Our ability to attract, motivate and retain key employees is restricted by provisions of the Bankruptcy Code, which limit or prevent our ability to implement a retention program or take other measures intended to motivate key employees to remain with the Company during the pendency of the bankruptcy. In addition, we must obtain Bankruptcy Court approval of employment contracts and other employee compensation programs. The loss of the services of such individuals or other key personnel could have a material adverse effect upon the implementation of our business plan, including our restructuring program, and on our ability to successfully reorganize and emerge from bankruptcy.

The prices of our debt and equity securities are volatile and, in connection with our reorganization, holders of our securities may receive no payment, or payment that is less than the face value or purchase price of such securities. The market price for our common stock has been volatile and our current common stock could be cancelled for no value or current stockholders could be substantially diluted under an agreement we reach with a group of our bondholders. Prices for our debt securities are also volatile and prices for such securities have generally been substantially below par. We can make no assurance that the price of our securities will not fluctuate or decrease substantially in the future. See “-- *Our shares are subject to risks associated with trading in an over-the-counter market*” for discussion of the risks of the Debtor’s securities trading in the over-the-counter market.

Accordingly, trading in our securities is highly speculative and poses substantial risks to purchasers of such securities, as holders may not be able to resell such securities or, in connection with our reorganization, may receive no payment, or a payment or other consideration that is less than the par value or the purchase price of such securities.

Risks Relating to the Oil and Natural Gas Industry, the Power Industry, and Our Business.

Oil and natural gas prices are highly volatile. A substantial or extended decline in oil prices and, to a limited extent, natural gas prices may adversely affect our business, financial condition, cash flow, liquidity or results of operations as well as our ability to meet our capital expenditure obligations and financial commitments necessary to implement our business plan. Any revenues, cash flow, profitability and future rate of growth we achieve will be greatly dependent upon prevailing prices for oil and gas. Our borrowing capacity and ability to obtain additional capital on attractive terms is also dependent on oil and gas prices.

Historically, oil and gas prices and markets have been volatile and are likely to continue to be volatile in the future. The price of oil per barrel has dropped precipitously by more than half since its high in June 2014. Oil and natural gas are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand for oil and gas, market uncertainty, and a variety of additional factors beyond our control. Those factors include among others:

- international political conditions (including wars and civil unrest, such as the recent unrest in the Middle East);
- the domestic and foreign supply of oil and gas;
- the level of consumer demand;
- weather conditions;
- domestic and foreign governmental regulations and other actions;
- actions taken by the Organization of Petroleum Exporting Countries (“OPEC”);
- the price and availability of alternative fuels; and
- overall global economic conditions.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but may also reduce the amount of oil and natural gas we can produce economically, if any, and, as such, may have a negative impact on our reserves. A continuation of low or significant declines in oil and natural gas prices may materially affect our future business, financial condition, results of operations, liquidity and borrowing capacity, and may require a reduction in the carrying value of our oil and gas properties and other assets. While our revenues may increase if prevailing oil and gas prices increase significantly, exploration and production costs and acquisition costs for additional properties and reserves may also increase. We currently do not enter into hedging arrangements or use derivative financial instruments such as crude oil forward and swap contracts to hedge our risk associated with fluctuations in commodity prices.

Our reserve estimates depend on many assumptions that may turn out to be inaccurate. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors that may turn out to be inaccurate. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the estimated value of reserves.

In order to prepare our reserve estimates, our independent petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data. The quality and reliability of this data can vary which in turn can have an effect on our reserve estimations. The process of estimating reserves also requires economic assumptions about matters, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise, and can vary.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates, and those variances may be material. Any significant variance could materially affect the estimated quantities and estimated value of our reserves.

We continue to assess new data we have collected or will collect in the near future, including the continuing assessment of acquired 3-D seismic data, analysis of cores drawn or to be drawn from our drilling program, production from our recent drilling program and planned acquisition of additional two dimensional ("2-D") and 3-D seismic data. The results of our assessments could affect reported reserves. In addition, our independent petroleum engineers may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices, availability of funds and other factors, many of which are beyond our control.

You should not assume that the estimated value of our proved reserves prepared in accordance with the SEC's guidelines is the current market value of our estimated oil reserves. We base the estimated value of future net cash flows from our proved reserves on an unweighted arithmetic average of the first-day-of-the month price for each month during the 12-month calendar year and year-end costs. Actual future prices, costs, taxes and the volume of produced reserves may differ materially from those used in the estimated value.

We have entered into a significant joint venture that may limit our operations and corporate flexibility in Block Z-1; actions taken by our joint venture partner in Block Z-1 may materially impact our financial position and results of operation, and we may not realize the benefits we expect from this joint venture. Various aspects of our Pacific Rubiales joint venture could materially impact us: The development of Block Z-1 is subject to the terms and conditions of a Joint Operating Agreement and we no longer have unlimited flexibility to control the development of this property. We share approval rights over major decisions and overall supervision of joint operations through a joint operating committee. Pacific Rubiales may have interests and goals that are inconsistent with ours. The performance of our joint venture partner's obligations under the Joint Operating Agreement is outside of our direct control. The ability or failure of our joint venture partner to pay its funding commitment could increase our costs of operations or result in reduced drilling and production of oil and gas, or loss of rights to develop Block Z-1. In addition, the ability or failure of us to pay for our share of the funding commitment could impair our ability to participate in the benefits of those projects and operations and may result in the loss of our rights to develop Block Z-1 with our joint operating partner. These restrictions may preclude transactions that could be beneficial to our shareholders. Pacific Rubiales is the technical operator of the field under an Operating Services Agreement. Their ability to deliver the continued safe and efficient operations of the Block under this agreement will have a material impact on us. Disputes between us and our joint venture partner, or actions taken by our joint venture partner, may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

We have not been profitable since we commenced operations and have historically had limited earnings from operations. To date, we have been unable to support our exploration and development activities solely through earnings from operations. At times when we have had a working capital surplus, the sources of our working capital surplus have generally been equity issuances, debt financings and asset sales, rather than revenue from operations, and we may incur working capital deficits in the future. We cannot provide any assurance that we will be profitable in the future or that we will be able to generate cash from operations or financings to fund working capital deficits.

We require additional financing for the exploration and development of our oil and gas properties and the construction of our proposed power generation facility, pipeline and gas processing facility. Since becoming a public company in 2004, we have funded our operations with the net proceeds of sales of securities, debt financing and the sale of a 49% participating interest in Block Z-1 for $150.0 million in 2012. We began to generate revenues from operations in the fourth quarter of 2007. We will need additional financing to fully implement our development plan. As we continue to execute our business plan and expand our operations, our cash generation from operations along with our commitments are likely to increase and, therefore, the likelihood of our seeking additional financing, either through the equity markets, debt financing, joint ventures, asset sales or a combination thereof may occur. If we are unable to timely generate or obtain adequate funds to finance our exploration and development plans, our ability to develop our oil and natural gas reserves may be limited or substantially delayed. In addition, if we are unable to fund our commitments under the joint venture with Pacific Rubiales, we could lose certain rights to develop Block Z-1. Such limitations or delays could result in a failure to realize the full potential value of our properties (and could affect the value of our properties as recorded in our financial statements) or could result in the potential loss of our oil and gas properties if we were unable to meet our obligations under the license agreements, which could, in turn, limit our ability to repay our debts.

In addition, inability to timely generate or obtain funds also could cause us to delay, scale back or abandon our plans for construction of our power generation facility, pipelines and gas processing facility, possibly resulting in further asset impairment charges. For the year ended December 31, 2014, we incurred impairments of $58.0 million related to our power plant and related equipment, due to recent developments, including Chapter 11 reorganization, that may change the extent or manner in which the asset may be used.

We may obtain future amounts required to fund our activities through additional equity and debt financing, joint venture arrangements, the sale of oil and gas interests, and/or future cash flows from operations. However, adequate funds may not be available when needed or may not be available on favorable terms. The exact nature and terms of such funding sources are unknown at this time, and there can be no assurance that we will obtain such funding or have funding available to adequately finance our future operations.

Changes in the financial and credit market may impact economic growth and may also affect our ability to obtain funding on acceptable terms. Global financial markets and economic conditions have been disruptive and volatile. Accordingly, the equity capital markets can become exceedingly distressed. Market discontinuities, credit risk pricing and weak economic conditions can make it difficult to obtain debt or equity capital funding. In addition, debt securities generally are susceptible to interest rate risk, which is the chance that bond prices overall will decline because of rising interest rates.

Due to these and possibly other factors, we cannot be certain funding will be available when and if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our exploratory and development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Our business involves many uncertainties and operating risks that may prevent us from realizing profits and can cause substantial losses. Our exploration and production activities may be unsuccessful for many reasons, including weather, the drilling of dry holes, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well will not ensure we will realize a profit on our investment. A variety of factors, including geological, regulatory and market-related factors can cause a well to become uneconomical or only marginally economical. Our business involves a variety of operating risks, including among others:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as earthquakes, tsunamis, typhoons and other adverse weather conditions;
- pipe, cement, subsea well or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; or
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

Experiencing any of these operating risks could lead to problems with any well bores, platforms, barges, gathering systems and processing facilities, which could adversely affect our present and future drilling operations. Affected drilling operations could further lead to substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory requirements, investigations and penalties;

- suspension of our operations; or
- repairs to resume operations.

If any of these risks occur, we may have to curtail or suspend any drilling or production operations and we could have our oil sales interrupted or suspended, which could have a material adverse impact on our financial condition, operations and ability to execute our business plan.

We have a limited operating history and have only been in commercial production in our Block Z-1 since November 2010. We are in the initial stages of developing our oil and natural gas reserves. We have transitioned from an extended well testing program into commercial production in the Corvina and Albacora fields in our Block Z-1 and have produced and sold oil under extended well testing programs in both fields in the past. We are also subject to all of the risks inherent in attempting to expand a relatively new business venture. Such risks include, but are not limited to, the possible inability to profitably operate our existing properties or properties to be acquired in the future, our possible inability to fully fund the development requirements of such properties, our possible inability to raise adequate amounts of debt or equity capital to meet our development obligations and our possible inability to acquire additional properties that will have a positive effect on our operations. We can provide no assurance that we will achieve a level of profitability that will provide a return on invested capital or that will result in an increase in the market value of our securities. Accordingly, we are subject to the risk that because of these factors and other general business risks noted throughout these "Risk Factors," we may not be able to profitably execute our plan of operation.

As of December 31, 2014, approximately 69% of our estimated net proved reserves were undeveloped. There can be no assurance that all of these reserves will ultimately be developed or produced. We own rights to oil and gas properties that have limited or no development. We can provide no guarantees that our properties will be developed profitably or that the potential oil and gas resources on the property will produce as expected if they are developed.

Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. We have prepared estimates of our oil reserves and the costs associated with these reserves in accordance with industry standards. However, the estimated costs may not be accurate, development may not occur as scheduled, or the actual results may not be as estimated. Our estimates of reserves may change from time to time depending upon our ability to produce such reserves in a timely manner. We may not have or be able to obtain the capital we need to develop these proved reserves.

We may not be able to drill proved undeveloped reserve locations included in our proved oil reserves that are scheduled to be drilled five years from initial disclosure of the related reserves. We may not be able to drill proved undeveloped locations scheduled to be drilled five years after their initial disclosure. This may result from unexpected governmental permitting delays, facilities limitations on the CX-11 offshore platform and contractual, as well as construction issues related to the CX-15 offshore platform in Block Z-1 located in environmentally sensitive remote locations. These proved undeveloped reserves are located in areas where we continue to actively drill. Proved undeveloped reserves scheduled to be drilled after the initial five year period could be, based on available precedent, challenged by regulatory authorities and there is a risk that our reserves would have to be revised to exclude these reserves.

We may not be able to replace our reserves. Our future success will depend upon our ability to find, acquire and develop oil and gas reserves that are economically recoverable. Any reserves we develop will decline as they are produced unless we are able to conduct successful revitalization activities or are able to replace the reserves by acquiring properties containing proven reserves, or both. To develop reserves and achieve production, we must implement our development and production programs, identify and produce previously overlooked or by-passed zones and shut-in wells, acquire additional properties or undertake other replacement activities. We can give no assurance that our planned development, revitalization, and acquisition activities will result in significant reserves replacement or that we will have success in discovering and producing reserves economically. We may not be able to locate geologically satisfactory property, particularly since we will be competing for such property with other oil and gas companies, most of which have much greater financial resources than we do. Moreover, even if desirable properties are available to us, we may not have sufficient funds with which to acquire or develop them.

Any failure to meet our debt obligations, including our Convertible Notes due 2015 or our Convertible Notes due 2017, would adversely affect our business and financial condition. We currently have the following convertible notes outstanding: (i) $59.9 million principal amount of the 2015 Convertible Notes, which bear interest semi-annually at a rate of 6.50% per year, and (ii) $168.7 million principal amount of the 2017 Convertible Notes, which bear interest semi-annually at a rate of 8.50% per year. The 2015 Convertible Notes matured with repayment of $59.9 million due on March 1, 2015. We exercised a provision under the indenture governing the 2015 Convertible Notes providing for a 10-day grace period on principal due and a 30-day grace period on interest due for a total amount due of approximately $62 million. The grace period on the principal amount due expired on March 10, 2015 and the grace period for interest amount due will expire on March 30, 2015. As a result of our decision to not pay the principal and interest on the 2015 Convertible Notes when due on March 1, 2015 and after exercise of the grace period until March 10, 2015, a cross default provision contained on the 2017 Convertible Notes was triggered. In addition, on March 9, 2015, the Debtor filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code, which was an event of default under the Indentures for the 2015 Convertible Notes and the 2017 Convertible Notes. Therefore all of our debt and related interest is considered due and callable once the default provisions were triggered. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the Indentures was automatically stayed as a result of the filing of the Chapter 11 Case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

As a result of the events of default, all debt has been classified as current at December 31, 2014. In addition, our auditors have expressed substantial doubt about our ability to continue as a going concern. See the Report of Independent Registered Public Accounting Firm included under Item 8. "Financial Statements and Supplementary Data." Our ability to meet our current and future debt obligations and other expenses will depend on the outcome of our Chapter 11 restructuring and our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our future debt, we may be required to refinance the debt, sell assets or sell shares of common stock on terms that we do not find attractive, if it can be done at all.

Our future operating revenue depends upon the performance of our properties. Our future operating revenue depends upon our ability to profitably operate our existing properties by drilling and completing wells that produce commercial quantities of oil and gas and our ability to expand our operations through the successful implementation of our plans to explore, acquire and develop additional properties. The successful development of oil and gas properties requires an assessment of potential recoverable reserves, future oil and gas prices, operating costs, potential environmental and other liabilities and other factors. Such assessments are necessarily inexact. No assurance can be given that we can produce sufficient revenue to operate our existing properties or acquire additional oil and gas producing properties and leases. We may not discover or successfully produce any recoverable reserves in the future, or we may not be able to make a profit from the reserves that we may discover. In addition, we regularly bring wells on or offline depending on technical performance, work-over requirements and, if applicable, testing period requirements. In the event that we are unable to produce sufficient operating revenue to fund our future operations, we will be forced to seek additional third-party funding, if such funding can be obtained. Such options would possibly include debt financing, sale of equity interests, joint venture arrangements, or the sale of oil and gas interests. If we are unable to secure such financing on a timely basis, we could be required to delay or scale back our operations. If such unavailability of funds continued for an extended period of time, this could result in the termination of our operations and the loss of an investor's entire investment.

Future oil and natural gas price declines or unsuccessful exploration efforts may result in significant charges or a write-down of our asset carrying values. We follow the successful efforts method of accounting for our investments in oil and natural gas properties. Under this method, oil and gas lease acquisition costs and intangible drilling costs associated with exploration efforts that result in the discovery of proved reserves and costs associated with development drilling, whether or not successful, are capitalized when incurred. Certain costs of exploratory wells are capitalized pending determinations that proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed.

If the net capitalized costs of our oil and natural gas properties, on a field basis, exceed the estimated undiscounted future net cash flows of that field, we must write down the costs of that field to our estimate of its fair value. Unproved properties are evaluated at the lower of cost or fair value. Accordingly, a significant decline in oil or natural gas prices or unsuccessful exploration efforts could cause a future write-down of our capitalized oil and natural gas property costs. In addition, if we are unable to find a market for gas from our onshore gas wells in Peru or no significant further activities are conducted on such wells, we may write off the costs of such wells.

We evaluate impairment of our proved oil and gas properties whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. In addition, write-downs would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date even if oil or natural gas prices increase.

Our oil and gas operations involve substantial costs and are subject to various economic risks. Our oil and gas operations are subject to the economic risks typically associated with exploration, development and production activities, including the necessity of significant expenditures to locate and acquire producing properties and to drill exploratory wells. The cost and length of time necessary to produce any reserves may be such that it will not be economically viable. In conducting exploration and development activities, the presence of unanticipated pressure or irregularities in formations, miscalculations or accidents may cause our exploration, development and production activities to be unsuccessful. In addition, the cost and timing of drilling, completing and operating wells is often uncertain. We also face the risk that the oil and/or gas reserves may be less than anticipated, that we will not have sufficient funds to successfully drill on the property, that we will not be able to market the oil and/or gas due to a lack of a market and that fluctuations in the prices of oil and/or gas will make development of those wells uneconomical. This could result in a total loss of our investments made in our operations.

We conduct offshore exploration, exploitation and production operations off the coast of northwest Peru, all of which are also subject to a variety of operating risks peculiar to the marine environment. Such risks include collisions, groundings and damage or loss from adverse weather conditions or interference from commercial or artesian fishing activities. These conditions can cause substantial damage to facilities, tankers and vessels, as well as interrupt operations. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties. Further our insurance may not adequately cover such events to reimburse us for the losses we may incur.

Disruptions of services provided by marine service providers could temporarily impair our operations and delay delivery of our oil to be sold. We depend on marine service providers to support our offshore operations in the Block Z-1. These services include, among others, tender support barges for our drilling operations and tank vessels for oil storage and transportation. Any disruptions or delay of the services provided by our marine service providers because of adverse weather or sea conditions, accidents, mechanical failures, scheduling conflicts with other tankers at the Talara refinery, insufficient personnel or other events could temporarily impair our operations, delay implementation of our business plan and increase our costs.

We currently have one customer for our crude oil sales and any disruption to their operations could temporarily impair our operations and delay delivery of our oil to be sold. Our oil is delivered by vessel to the refinery owned by the Peruvian national oil company, Petroleos del Peru - PETROPERU S.A., in Talara, located approximately 70 miles south of the CX-11 platform. Produced oil is kept in production inventory until inventory quantities are at a sufficient level to make a delivery to the refinery in Talara. Although all of our oil sales are to Petroperu, we believe that the loss of Petroperu as our sole customer would not materially impact our business because we could readily find other purchasers for our oil production both in Peru and throughout the world. However this could take time and effort to re-market this crude oil and there can be no guarantee that we will be successful at this effort. Should we not be successful it would impact our cash flows related to oil sales.

We are assessing additional joint venture or partner relationships in our other blocks and our power generation project which subjects us to additional risks that could have a material adverse effect on the success of our operations, our financial position and our results of operations. We may enter into additional joint venture arrangements in the future for Block Z-1 or our other blocks and our power generation project. These third parties may have obligations that are important to the success of the joint venture, including technical and operational as well as the obligation to pay their share of capital and other costs of the joint venture. The performance of these obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our direct control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected. Any joint venture arrangements we may enter into may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their shares of joint venture liabilities;
- we may incur liabilities as a result of actions taken by our joint venture partners;
- our joint venture partners may have economic or business interests or goals that are inconsistent with, or adverse to, our interests or goals;

- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint venture or to resolve disagreements with our joint venture partner could adversely affect our ability to transact the business that is the subject of such joint venture and increase our expenses, which would in turn negatively affect our financial position and results of operations.

Risks Related to Our Geographic Location and Concentration.

If we fail to comply with the terms of certain contracts related to our foreign operations, we could lose our rights under each of those contracts. The terms of each of our Peruvian oil and gas license contracts require that we perform certain minimum work programs in each period under the contracts, such as seismic acquisition, processing and interpretations and the drilling of required wells in accordance with those contracts and agreements. We are also required to conduct environmental impact studies and environmental impact assessments and establish our ability to comply with environmental regulations. Our Peruvian operating subsidiary that holds the license contracts has posted guaranties as required in favor of Perupetro to insure performance for the minimum work program for the applicable period under the license contracts, generally in the amount of fifty percent of the estimated value of the minimum work program for the period. BPZ Resources, Inc. has also issued a parent company guaranty as required in favor of Perupetro providing for joint and several liability to Perupetro with respect to fulfillment of such minimum work programs for the applicable periods. If we (i) fail to timely perform those activities as required, (ii) we fail to maintain valid subsidiary or parent guaranties in favor of Perupetro and do not replace the guaranty within the time allowed under the license contract or (iii) there has been a declaration of insolvency, dissolution, liquidation or bankruptcy has been pronounced of the entity that granted the guaranty and we have not provided notice to Perupetro following receipt of Perupetro's request for a replacement guaranty, identifying the company that will assume such guaranty, once qualified and accepted by Perupetro, then our current production and sale of oil could be suspended, we could lose our rights under a particular contract and/or lose the amounts we have posted as a guaranty for the performance of such activities, which would result in a significant loss to us.

The geographic concentration of our properties in northwest Peru and southwest Ecuador subjects us to an increased risk of loss of revenue or curtailment of production from factors affecting that region specifically. The geographic concentration of our properties in northwest Peru and southwest Ecuador and adjacent waters means that some or all of our properties could be affected by the same event should that region, for example, experience:

- natural disasters such as earthquakes and/or severe weather (such as the effects of "El Niño," which can cause excessive rainfall and flooding in Peru and Ecuador);
- delays or decreases in production, the availability of equipment, facilities or services;
- delays or decreases in the availability of capacity to transport, gather or process production; or
- changes in the political or regulatory environment.

Because all our properties could experience the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area.

Our operations in Peru and Ecuador involve substantial costs and are subject to certain risks because the oil and gas industry in Peru and Ecuador is less developed in comparison to the United States. Because the oil and gas industry in Peru and Ecuador is less developed than in the United States, our drilling and development operations, in many instances, will take longer to complete and may cost more than similar operations in the United States. The availability of technical expertise and specific equipment and supplies may be more limited or costly in Peru and Ecuador than in the United States. If we are unable to obtain, or unable to obtain without undue cost, drilling rigs, equipment, supplies or personnel, our exploitation and exploration operations could be delayed or adversely affected, which could have a material adverse effect on our business, financial condition or results of operations. Furthermore, once oil and natural gas production is recovered, there are fewer ways to transport it to market for sale. Marine transportation for our offshore operations is subject to risks such as adverse weather conditions, collisions, groundings and other risks of damage or delay. Pipeline and trucking operations are subject to uncertainty and lack of availability. Oil and natural gas pipelines and truck transport travel through miles of territory and are subject to the risk of diversion, destruction or delay. We expect that such factors will continue to subject our international operations to economic and operating risks that companies with domestic operations do not experience.

Along with the general instability that comes from international operations, we face political and geographical risks specific to working in South America. All of our oil and gas properties are located in South America, and specifically in Peru and Ecuador. The success and profitability of our international operations may be adversely affected by risks associated with international activities, including among others:

- economic, labor, and social conditions;
- local and regional political instability;
- tax laws (including host-country export, excise and income taxes and U.S. taxes on foreign operations); and
- fluctuations in the value of the U.S. dollar versus the local currencies in which oil and gas producing activities may be conducted.

Legal uncertainty, operating expenses and fluctuations in exchange rates may make our assumptions about the economic viability of our oil and gas properties incorrect. If these assumptions are incorrect, we may not be able to earn sufficient revenue to cover our costs of operations.

Social and political unrest in Peru and Peruvian election results could cause heightened scrutiny over oil and gas regulatory matters. Peru's next Presidential election will be held in April 2016. The electoral campaigns could bring heightened attention to various topics, including the regulation of oil and gas companies operating in Peru, and related environmental law compliance. These elections and the result from the election could result in increased environmental regulation, including additional regulation and oversight of the hydrocarbon and mining sectors, and regulation to combat global climate change and decrease the emission of greenhouse gases. In addition, the elections could result in increased scrutiny of the royalties on oil and gas production, which could help fund domestic social-regeneration projects.

We are subject to numerous foreign laws and regulations of the oil and natural gas industry that can adversely affect the cost, manner or feasibility of doing business. Our operations are subject to extensive foreign laws and regulations relating to the exploration for oil and natural gas and the development, production and transportation of oil and natural gas, as well as electrical power generation. Because the oil and gas industry in the countries in which we operate is less developed than elsewhere, changes in laws and interpretations of laws, including an interpretation that the oil period under the License Contract in Peru will not extend to the full 40 year period provided for gas operations, are more likely to occur than in countries with a more developed oil and gas industry. Future laws or regulations, as well as any adverse change in the interpretation of existing laws or our failure to comply with existing legal requirements may harm our results of operations and financial condition. We may be required to make our share of contributions to large and unanticipated expenditures to comply with governmental regulations, such as:

- work program guarantees and other financial responsibility requirements;
- taxation;
- royalty requirements;
- customer requirements;
- employee compensation and benefit costs;
- operational reporting;
- environmental and safety requirements; and
- unitization requirements.

Under these laws and regulations, we could be liable for our share of:

- personal injuries;
- property and natural resource damages;
- unexpected employee compensation and benefit costs;
- governmental infringements and sanctions; and
- unitization payments.

Compliance with, or breach of, laws relating to the discharge of materials into, and the protection of, the environment can be costly and could limit our operations. As an owner or lessee and operator of oil and gas properties in Peru and Ecuador, we are subject to various national, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, (i) impose liability on the owner or lessee under an oil and gas lease for the cost of property damage, oil spills, discharge of hazardous materials, remediation and clean-up resulting from operations; (ii) subject the owner or lessee to liability for pollution damages and other environmental or natural resource damages; and (iii) require suspension or cessation of operations in affected areas. We have established practices for continued compliance with environmental laws and regulations and we believe the costs incurred by these policies and procedures so far have been necessary business costs in our industry. However, there is no assurance that changes in or additions to laws or regulations regarding the protection of the environment will not increase such compliance costs, or have a material adverse effect upon our capital expenditures, earnings or competitive position.

We are subject to laws and regulations that can adversely affect the cost, manner and feasibility of our planned operations. The exploration for, and the development, production and sale of oil and gas in South America, and the construction and operation of power generation and gas processing facilities and pipelines in South America are subject to extensive environmental, health and safety laws and regulations. Our ability to conduct continued operations is subject to satisfying applicable regulatory and permitting controls. For example, we are required to obtain an environmental permit or approval from the government in Peru prior to conducting seismic operations, drilling a well or constructing a pipeline in Peruvian territory, including the waters offshore of Peru, where we intend to conduct future oil and gas operations. We are also required to comply with numerous environmental regulations in order to transition from exploration into production in any new fields we develop. Additionally, environmental laws and regulations promulgated in Peru impose substantial restrictions on, among other things, the use of natural resources, interference with the natural environment, the location of facilities, the handling and storage of hazardous materials such as hydrocarbons, the use of radioactive material, the disposal of waste, and the emission of noise and other activities. The laws create additional monitoring and reporting obligations in the event of any spillage or unregulated discharge of hazardous materials such as hydrocarbons. Failure to comply with these laws and regulations also may result in the suspension or termination of our planned drilling operations and subject us to administrative, civil and criminal penalties.

Our current permits and authorizations and our ability to obtain future permits and authorizations may, over time, be susceptible to increased scrutiny, resulting in increased costs, or delays in receiving appropriate authorizations. In particular, we may experience delays in obtaining permits and authorizations in Peru necessary for our operations.

Compliance with these laws and regulations may increase our costs of operations, as well as further restrict our foreign operations. Moreover, these laws and regulations could change in ways that substantially increase our costs. These laws and regulations have changed in the past and have generally imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly higher than those we currently anticipate, thereby increasing our overall costs. Any failure to comply with these laws and regulations could cause us to suspend or terminate certain operations or subject us to administrative, civil or criminal penalties. Any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and our ability to implement our plan of operation.

BPZ E&P is subject to labor and health and safety regulations and may be exposed to liabilities and potential costs for compliance. BPZ E&P is subject to Peruvian government and local labor and health and safety laws and regulations that govern, among other things, the relationship between BPZ E&P and its employees and the health and safety of BPZ E&P's employees. For example, according to the Peruvian Safety and Health at Work Law (Ley de Seguridad y Salud en el Trabajo), Law No. 29783, BPZ E&P is required to adopt certain measures to safeguard the health and safety of its employees, as well as third parties, in its facilities. If compliance by BPZ E&P with such requirements should be reviewed by the applicable authorities and if an adverse final decision that BPZ E&P violated any labor laws, including the Peruvian Safety and Health at Work Law, should be issued in an administrative process, BPZ E&P may be exposed to penalties and sanctions, including the payment of fines and, depending on the level of severity of the infraction, exposed to the closure of its facilities and/or stoppage of its operations and the cancellation or suspension of governmental registrations, authorizations and licenses, any one of which may result in interruption or discontinuity of activities in BPZ E&P's facilities, and materially and adversely affect BPZ E&P.

Our management team has limited experience in the power generation business. Our plan of operation includes constructing power generation and pipelines in Peru. However, the experience of our management team has primarily been in the oil and natural gas exploration and production industry and we have limited experience in the power generation business. We have hired a Commercial Manager who has experience related to the power generation business. We continue relying on consultants and outside engineering and technical firms to provide the expertise to plan and execute the power generation aspects of our strategy and we have not yet hired all necessary full-time employees to manage this line of business. No assurance can be given that we will be able to recruit and hire qualified personnel on acceptable terms. Inability to hire such key technical personnel when necessary may adversely affect our gas-to-power project.

Construction and operation of power generation and pipelines involve significant risks and delays that cannot always be covered by insurance or contractual protections. The construction of power generation and pipelines involve many risks, including:

- supply interruptions;
- work stoppages;
- labor disputes;
- social unrest;
- inability to negotiate acceptable construction, supply or other contracts;
- inability to obtain required governmental permits and approvals;
- weather interferences;
- unforeseen engineering, environmental and geological problems;
- unanticipated cost overruns;
- possible delays in the acquisition of support equipment necessary for our gas turbines;
- possible delays in transporting the necessary equipment to our planned facility in Northern Peru;
- possible delays in connection with power plant construction;
- possible delays or difficulties in completing financing arrangements for the gas-to-power project; and
- possible difficulties or delays with respect to any necessary Peruvian regulatory compliance.

The construction and future operation of these facilities involve all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performances below expected levels of output or efficiency. We intend to maintain commercially reasonable levels of insurance, where such insurance is available and cost-effective, obtain warranties from vendors and obligate contractors to meet certain performance levels. However, the coverage or proceeds of any such insurance, warranties or performance guarantees may not be adequate to cover lost revenues or increased expenses. Any of these risks could cause us to operate below expected capacity levels, which in turn could result in lost revenues, increased expenses and higher costs.

The success of our gas-to-power project will depend, in part, on the existence and growth of markets for natural gas and electricity in Peru. Peru has a well-developed and stable market for electricity. Hydroelectric and gas-fired thermal power plants are the primary sources of electric generation, with each source providing approximately 50%. Hydroelectric plants are much less expensive to operate than plants that utilize natural gas, but they are subject to variable output based on rainfall and reservoir levels. Peru has natural gas reserves and production, but does not have a well-developed natural gas infrastructure, particularly in northwest Peru where we operate. Our immediate business plan relies on the continued stability of the power market in Peru. We currently do not expect to complete our power plant earlier than 2017. Further, we cannot guaranty that our efforts to complete the gas-to-power project will be successful. Our assessment of the future power market and demand in Peru and the near-term viability of the project could be inaccurate. We are subject to the following risks:

- relatively more favorable business conditions for hydroelectric plants, a material reduction in power demand or other competitive issues may adversely affect the demand and prices for the electricit that we expect to produce by the time the power plant is completed;
- our lifting costs could exceed the minimum wholesale power prices available, making the sale of our gas uneconomical;

- gas supply and reserves may not develop as anticipated;
- potential disruptions or changes to the regulation of the natural gas or power markets in the region could occur by the time our power plant is completed, or we may not receive the necessary environmental or other permits and governmental approvals necessary to operate our power plant or to proceed with the plant in a timely manner;
- although we plan to enter into long-term contracts to sell a significant part of our future power production, there can be no assurance that we will be successful in obtaining such contracts or that they will be on favorable terms; and
- we will be subject to the general commercial issues related to being in the power business, including the credit-worthiness of, and collections from future customers and the ability to profitably operate our future power plant.

We are subject to the Foreign Corrupt Practices Act (the "FCPA"), and our failure to comply with the laws and regulations thereunder could result in material adverse effect on our business. We are subject to the FCPA, and our failure to comply with the laws and regulations thereunder could result in penalties which could harm our reputation and have a material adverse effect on our business, results of operations and financial condition. We are subject to the FCPA, which generally prohibits companies and their intermediaries from making improper payments to foreign officials to secure any improper advantage for the purpose of obtaining or keeping business and/or other benefits. Since all of our oil and gas properties are in Peru and Ecuador, there is a risk of potential FCPA violations. We have a FCPA policy and a compliance program designed to ensure that we, our employees and agents comply with the FCPA. There is no assurance that such policy or program will work effectively all of the time or protect us against liability under the FCPA for actions taken by our agents, employees and intermediaries with respect to our business or any businesses that we acquire. Any violation of these laws could result in monetary penalties against us or our subsidiaries and could damage our reputation and, therefore, our ability to do business.

Competition for oil and natural gas properties and prospects is intense; many of our competitors have larger financial, technical and personnel resources that give them an advantage in evaluating and obtaining properties and prospects. We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and natural gas and securing trained personnel and equipment. In addition, changes in Peruvian government regulation have enabled multinational and regional companies to enter the Peruvian energy market. We compete with other companies in our industry when acquiring new leases or oil and gas properties. Competition in our business activities has increased and may increase further, as existing and new participants expand their activities as a result of these regulatory changes. Many of our competitors possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than we have. For example, if several companies are interested in an area, Perupetro may choose to call for bids, either through international competitive biddings or through private bidding processes by invitation, and award the contract to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay. On the acquisition opportunities made available to us, we may compete with other companies in our industry for properties operated by third parties through a private bidding process, direct negotiations or some combination thereof. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the business practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence. Our size and current financial status may impair our ability to compete for oil and natural gas properties and prospects.

Other Business Risks.

We are subject to routine and ongoing tax audits with the United States Internal Revenue Service ("IRS") and tax authorities for other jurisdictions that could result in additional tax assessment. We have been subject to audits by the IRS and the tax and customs office in Peru ("SUNAT"). If the IRS or SUNAT disagrees with the positions taken by us on our tax returns, we could have additional tax liability, including interest and penalties. If our positions are not upheld through the appeal process and we ultimately pay such amounts, the payment could have an adverse effect on our financial results and cash flows.

Failure to generate taxable income and realize our deferred tax assets in Peru could have a material adverse effect on our financial position and results of operations. The assessment of deferred tax assets and of valuation allowances associated with deferred tax assets require management to make estimates and judgments about the realization of deferred tax assets, which realization will be primarily based on forecasts of future taxable income. Such estimates and judgments are inherently uncertain. We evaluate our deferred tax assets generated in Peru for realization annually or whenever there is an indication that they are not realizable. The ultimate realization of our foreign deferred tax assets is dependent upon the generation of future taxable income in Peru within the time periods required by applicable tax statutes. Should we determine in the future that it is more likely than not that some portion or all of our foreign deferred tax assets will not be realized, we will be required to record a valuation allowance in connection with these deferred tax assets. Such valuation allowance, if taken, would be recorded as a charge to income tax expense and our financial condition and operating results would be adversely affected in the period such determination is made.

Insurance does not cover all risks. Exploration for, and the production of, oil and natural gas can be hazardous, involving unforeseen occurrences such as blowouts, cratering, fires and loss of well control, which can result in (i) damage to or destruction of wells and/or production facilities, (ii) damage to or destruction of formations, (iii) injury to persons, (iv) loss of life, or (v) damage to property, the environment or natural resources. As a result, we presently maintain insurance coverage in amounts consistent with our business activities and to the extent required by our license contracts. Such insurance coverage includes certain physical damage to our and third parties' property, hull and machinery, protection and indemnity, employer's liability, comprehensive third party general liability, workers' compensation and certain pollution and environmental risks. However, we are not fully insured against all risks in all aspects of our business, such as political risk, civil unrest, war, business interruption, environmental damage and reservoir loss or damage. Further, no such insurance coverage can insure for all operational or environmental risks. The occurrence of an event that is not insured or not fully insured could result in losses to us. For example, uninsured or under insured environmental damages, property damages or damages related to personal injuries could divert capital needed to implement our plan of operation. If any such uninsured losses are significant, we may have to curtail or suspend our drilling or other operations until such time as replacement capital is obtained, if ever, and this could have a material adverse impact on our financial position.

The loss of senior management or key technical personnel could adversely affect us. We have engaged certain members of management who have substantial expertise in the type of endeavors we presently conduct and the geographical areas in which we conduct them. We do not maintain any life insurance against the loss of any of these individuals. To the extent their services become unavailable, we will be required to retain other qualified personnel. There can be no assurance we will be able to recruit and hire qualified persons on acceptable terms. Similarly, the oil and gas exploration industry requires the use of personnel with substantial technical expertise. In the event that the services of our current technical personnel become unavailable, we will need to hire qualified personnel to take their place. No assurance can be given that we will be able to recruit and hire such persons on acceptable terms. Inability to replace lost members of management or key technical personnel may adversely affect us.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss. Businesses have become increasingly dependent on digital technologies to conduct day-to-day operations. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial of service on websites.

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has also increased rapidly. The complexity of the technologies needed to extract oil and gas in increasingly difficult physical environments, such as deep water, and global competition for oil and gas resources make certain information more attractive to thieves.

We depend on digital technology, including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology.

Our technologies, systems and networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- unauthorized access to seismic data, reserves information, operational results or other sensitive or proprietary information could have a negative impact on our competitive position in developing our o and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in a dry hole cost or even drilling incidents;
- data corruption or operational disruption of production infrastructure could result in loss of production or accidental discharge;
- a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt one of our major projects, effectively delaying the start of cash flows from the project;
- a cyber-attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activitie resulting in a loss of revenues;
- a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- significant business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

Although to date we have not experienced any material losses relating to cyber incidents, there can be no assurance that we will not suffer such losses in the future. As cyber threats 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 information security vulnerabilities.

Risk Factors Related to Our Securities.

The market price of our common stock has been and will likely continue to be volatile. The market price of our common stock has been highly volatile and subject to wide fluctuations. In addition, the trading volume in our common stock may fluctuate and cause significant price variations to occur. The market price and trading volume of our stock is likely to continue to be highly volatile due to the risks and uncertainties described in this section of the Form 10-K, as well as other factors including:

- actual or anticipated fluctuations in our results of operations;
- our voluntary filing under Chapter 11 of the United States Bankruptcy Code;
- our delisting from the NYSE;
- failure to be covered by securities analysts, or failure by us to meet securities analysts’ expectations;
- success of our operating strategies;
- decline in the stock price of companies that are our peers;
- realization of any of the risks described in this section; or
- general market and economic conditions.

From January 1, 2014 through December 31, 2014, the closing price of our common stock as reported on the NYSE ranged from a high of $3.40 to a low of $0.17. As a result of this volatility and our recent filing under Chapter 11 of the United States Bankruptcy Code, an investment in our stock is subject to substantial risk. A plan of reorganization may result in holders of our capital stock receiving very limited or no distribution on account of their interests and cancellation of their existing stock. Furthermore, the volatility of our stock price could negatively impact our ability to raise capital in the future.

In addition, the stock market has experienced in the past, and may in the future experience extreme price and volume fluctuations. These market fluctuations may materially and adversely affect the trading price of our common stock, regardless of our actual operating performance.

Our shares are subject to risks associated with trading in an over-the- counter market. On March 2, 2015, we were notified by the NYSE that the staff of NYSE Regulation, Inc. had determined to commence proceedings to delist our common stock from the NYSE. Trading of our common stock on the NYSE was suspended immediately and currently only trades in the over-the-counter market. Securities traded in the over-the-counter market generally have significantly less liquidity than securities traded on a national securities exchange, through factors such as a reduction in the number of investors that will consider investing in the securities, the number of market makers in the securities, reduction in securities analyst and news media coverage and lower market prices than might otherwise be obtained. As a result, holders of shares of our common stock may find it difficult to resell their shares at prices quoted in the market or at all. Furthermore, because of the limited market and generally low volume of trading in our common stock that could occur, the share price of our common stock could be more likely to be affected by broad market fluctuations, general market conditions, fluctuations in our operating results, changes in the markets perception of our business, and announcements made by us, our competitors or parties with whom we have business relationships. With respect to the Company, in some cases, we may be subject to additional compliance requirements under applicable state laws in the issuance of our securities. The lack of liquidity in our common stock may also make it difficult for us to issue additional securities for financing or other purposes, or to otherwise arrange for any financing we may need in the future. In addition, we may experience other adverse effects, including, without limitation, the loss of confidence in us by current and prospective suppliers, customers, employees and others with whom we have or may seek to initiate business relationships.

Investor profits, if any, may be limited for the foreseeable future. In the past, we have never paid a dividend. Further we have voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code and common shareholders may receive very limited, if any amount on their investment in the event a plan of reorganization is approved by the Bankruptcy Court as such plan may not assign any equity interest to prior shareholders. We do not anticipate paying any dividends in the near future following our reorganization. Accordingly, investors in our common stock may not derive any profits from their investment in us for the foreseeable future, other than through any price appreciation of our common stock that may occur. Further, any appreciation in the price of our common stock may be limited or nonexistent, or in fact it could decline, as long as we continue to have operating losses and are subject to the Bankruptcy Court proceedings. We have not been profitable and have accumulated a deficit of operations totaling $539.5 million through December 31, 2014. To date we have had limited revenue and no earnings from operations. There can be no assurances that sufficient revenue to cover total expenses can be achieved until, if at all, we can complete our reorganization and fully implement our operational plan. Accordingly we urge extreme caution in making an investment decision with respect to our securities.

Additional infusions of capital may have a dilutive effect on existing shareholders. We have voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code and common shareholders may receive very limited, if any amount on their investment in the event a plan of reorganization is approved by the Bankruptcy Court as such plan may not assign any equity interest to prior shareholders. Any financing received through the Chapter 11 proceedings will be senior in priority to all of our other debt and equity.

Our certificate of formation does not provide for preemptive rights, although by contract we have granted the International Finance Corporation (“IFC”) the right to purchase shares of our common stock to retain its proportionate ownership pursuant to the Subscription Agreement dated December 16, 2006 by and between IFC and us. Any future additional equity financing that we receive may involve substantial dilution to our then-existing shareholders. In addition, we are authorized to issue up to 25,000,000 shares of preferred stock, the rights and preferences of which may be designated by our Board of Directors. If we issue shares of preferred stock, such preferred stock may have rights and preferences that are superior to those of our common stock.

Our corporate organizational documents and the provisions of Texas law to which we are subject may delay or prevent a change in control of us that some shareholders may favor. Our certificate of formation and bylaws contain provisions that, either alone or in combination with the provisions of Texas law described below, may have the effect of delaying or making it more difficult for another person to acquire us by means of a hostile tender offer, open market purchases, a proxy contest or otherwise. These provisions include:

- A board of directors classified into three classes of directors with each class having staggered, three-year terms. As a result of this provision, at least two annual meetings of shareholders may be require for the shareholders to change a majority of our board of directors.
- The board's authority to issue shares of preferred stock without shareholder approval, which preferred stock could have voting, liquidation, dividend or other rights superior to those of our commo stock. To the extent any such provisions are included in any preferred stock, they could have the effect of delaying, deferring or preventing a change in control.
- Our shareholders cannot act by less than unanimous written consent and must comply with the provisions of our bylaws requiring advance notification of shareholder nominations and proposals. Thes provisions could have the effect of delaying or impeding a proxy contest for control of us.
- Provisions of Texas law, which we did not opt out of in our certificate of formation, that restrict business combinations with "affiliated shareholders" and provide that directors serving on staggere boards of directors, such as ours, may be removed only for cause.

Any or all of these provisions could discourage tender offers or other business combination transactions that might otherwise result in our shareholders receiving a premium over the then current market price of our common stock. Further we have voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code and there may be a change in control on the execution of an agreed upon plan of reorganization through the Bankruptcy Court proceeding.

Our officers, directors, entities affiliated with them and certain institutional investors may exercise significant control over us. In the aggregate, our management and directors own or control approximately 6.5% of our common stock, and several institutional investors own approximately another 22.2% of our common stock, issued as of December 31, 2014. These shareholders own in total approximately 28.7%, and, if acting together, would be able to significantly influence all matters requiring approval by our shareholders, including the election of directors and the approval of mergers or other business combination transactions. However we have voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code and the ability of our officers, directors and institutional investors to exercise significant control over us may be significantly diminished or removed entirely through the Bankruptcy Court proceeding.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Offices

Our corporate headquarters office is in Houston, Texas, where we lease approximately 13,300 square feet of office space under a lease agreement which expires in February 2016. We also currently lease administrative offices and warehouses in Peru. The administrative offices and warehouse leased areas are approximately 13,700 square feet and 105,000 square feet, respectively. The administrative offices leases expire in March 2016 and in March 2019 and the warehouse lease expires in July 2038. Additionally, we lease an administrative office in Quito, Ecuador of 829 square feet under a month-to-month lease and an office in Victoria, Texas.

Properties in Peru

We currently have rights to four properties in northwest Peru. We have working interests in license contracts of 51% in offshore Block Z-1, 100% in onshore Block XIX, 100% in onshore Block XXII and 100% in onshore Block XXIII. The license contracts afford an initial exploration phase of seven years. As described below, each license contract provides for additional exploration periods which can extend the exploration phase of the license contract. If exploration efforts are successful, the license contract's term can extend up to 30 years for oil production and up to 40 years for gas production. In the event a block contains both oil and gas, as is the case in the Block Z-1 contract, the 40-year term may apply to oil production as well. These four blocks cover a combined area of approximately 2.2 million gross acres.

The following table is a summary of our properties in northwest Peru. As of December 31, 2014, only acreage in Block Z-1 has been partially developed.

PROPERTY	BASIN	BPZ'S OWNERSHIP	LICENSE CONTRACT SIGNED	UNDEVELOPED ACRES		DEVELOPED ACRES		PRODUCTIVE WELLS (1) (2) (3)	
				Gross	Net	Gross	Net	Gross	Net
Block Z-1	Tumbes/Talara	51%	November 2001	554,200	282,642	800	408	20	10.
Block XIX	Tumbes/Talara	100%	December 2003	473,000	473,000				
Block XXII	Lancones/Talara	100%	November 2007	912,000	912,000				
Block XXIII	Tumbes/Talara	100%	November 2007	230,000	230,000				
Total				2,169,200	1,897,642	800	408	20	10.

(1) Does not include the CX11-16X well which tested quantities of gas which we believe to be of commercial amounts and is currently shut-in. Until such time as sufficient funding has been secured an the necessary infrastructure is in place for our gas-to power project, we cannot classify any of these reserves as proved SEC reserves nor refer to the well as productive.

(2) Includes all oil producing wells we have developed. At December 31, 2014, 17 gross (8.7 net) wells were producing consistently and 3 gross (1.5 net) wells were producing intermittently.

(3) Does not include the CX11-22D well which has been converted to a gas and water reinjection well, the A-12F well which has been converted to a gas reinjection well or the A-17D well which is a wate reinjection well.

Description of Block Z-1 and License Contract

Block Z-1, a coastal offshore area encompassing approximately 555,000 gross acres, is situated at the southern end of the Gulf of Guayaquil in northwest Peru. Geologically, the block lies within the Tumbes Basin. From the coastline, water depths increase gradually. The average water depth of the area is approximately 200 feet and approximately 10% of the area has depths ranging from 500 feet up to 1,000 feet. Located within Block Z-1 are five structures which were drilled in the 1970s and 1980s by previous operators, including Tenneco Inc. and Belco Oil and Gas Corporation ("Belco"). These structures are known as the Albacora, Barracuda, Corvina, Delfin and Piedra Redonda fields. With the exception of the Barracuda field, the other four fields have had exploration wells drilled that tested positive for oil or gas in what we believe to be economic quantities while drilling at depths ranging from 6,000 to 12,000 feet. However, at the time the wells were drilled, it was not considered economically viable to produce and sell natural gas from the fields. Consequently, the wells were either suspended or abandoned.

In the Corvina field, five wells were drilled, including two wells drilled by Tenneco Inc. in the mid-1970s and three wells drilled by Belco in the late 1970s and early 1980s. Two drilling and production platforms were set up by Belco during this period in the Corvina field. The first platform was located in the East Corvina prospect field and, based on the engineering study, was not suitable for our future development plans and therefore requires us to build a new platform prior to initiating any drilling activities in this section of the Corvina field. The second platform, CX-11, is located in the West Corvina development field and is currently being used in our West Corvina drilling and production activities. All five of the previously drilled wells in the Corvina field encountered indications of natural gas and apparent reservoir-quality formations. In September 2012, our CX-15 platform was anchored at the West Corvina field location, one mile south of the existing CX-11 platform. We completed the installation of the CX-15 platform in the West Corvina field, and in July 2013 we spudded the first development well from the platform. Production from the first well began in October 2013.

In the Albacora field, the original drilling and production platform, the A platform, was set by Tenneco Inc. in the mid-1970s, after discovering oil and gas with the 8X-2 well. Tenneco Inc. drilled two wells from that platform that were plugged and abandoned. In the late 1970s, Belco drilled three oil wells which produced oil for a very limited time. The Albacora field is located in the northern part of our offshore Block Z-1. The A platform is still in place in the Albacora field and has been repaired, refurbished and placed into service by us. In late 2009, we completed the A-14XD oil well that is still producing, and in 2010 we drilled a second well that was considered dry and was later converted into a water disposal well. After interpreting the new 3-D seismic, we began drilling with a new development well from the A platform in September 2013 which was completed and put into production in December 2013.

In the Piedra Redonda field, two wells were drilled by Belco in the late 1970s and early 1980s. Indications of natural gas were present in both wells. One well was completed and tested gas on a long-term test, while the other well encountered abnormally high pressures and was abandoned for mechanical reasons prior to reaching its intended total depth. After conducting engineering feasibility studies, we have determined the existing platform located in the Piedra Redonda field is not suitable for our future development plans and therefore we must consider other options for development in this field. We are evaluating the options for this platform. In any case, we do not expect to recomplete the previously drilled and completed well by Belco due to our uncertainty of the mechanical condition and potentially high wellhead pressure of the well.

We have received the permit to install a platform and begin exploratory drilling in the Piedra Redonda prospect. The Piedra Redonda prospect is located south of the Corvina field. Construction of the platform began in the third quarter of 2014. In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Piedra Redonda platform. We will be storing the platform in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months.

Also, we have received the permit to install a platform and begin exploratory drilling in the Delfin prospect. The Delfin prospect is located southwest of the Corvina field. Construction of the platform began in the third quarter of 2014. In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Delfin platform and drilling of the Delfin well. We will be storing the platform in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months.

We originally acquired our initial interest in Block Z-1 in a joint venture with Syntroleum Peru Holdings Limited, Sucursal del Peru, under an exploration and production license contract dated November 30, 2001, with an effective date of January 29, 2002. Under the original contract, BPZ owned a 5% non-operating working interest, along with the right of first refusal, in the Block. Syntroleum later transferred its interest to Nuevo Peru ltd., Sucursal del Peru. Subsequent to the merger of Nuevo Energy, Inc. and Plains Exploration and Production Company, Nuevo Energy, Inc. transferred its interest in Block Z-1 to BPZ which then assumed a 100% working interest, as well as the remaining obligations under the contract. Perupetro approved the assumption of Nuevo's interest by BPZ and the designation of BPZ as a qualified operator under the contract in November 2004. This action was subject to official ratification and issuance of a Supreme Decree by the government of Peru, which was issued in February 2005. Accordingly, an amended contract was signed with Perupetro naming BPZ as the owner of 100% of the participation under the License Contract.

In December 2012, we completed the sale of a 49% participating interest in the Block Z-1 License Contract to Pacific Rubiales. We now own 51% participating interest in Block Z-1.

The License Contract provides for an initial exploration phase of seven years, and a three year extension of this phase at the discretion of Perupetro upon application by the Operator. Each period has a commitment for exploration activities and requires a financial guarantee to secure the performance of the work commitment during such period. Block Z-1 is currently in the exploitation phase.

The Block Z-1 License Contract permits us to keep the current contract area under exploration for a total of six additional years divided in three two-year periods with each committing us to additional exploration activities. The additional exploration commitment requires us to drill one exploratory well, or perform ten exploratory work units per each 10,000 hectares (approximately 25,000 acres), every two years for up to a maximum period of six years, in order to keep the remaining area under contract. We received approval from Perupetro for the initial two-year period and have committed to drill an exploratory well. The end date for the initial two-year period will be determined from the agreed approval date of the environmental permit with Perupetro.

A performance bond of $1.1 million was posted for cash collateral of $0.2 million related to the exploitation period. The performance bond will be released at the end of the exploitation period if the work commitment for that period has been satisfied. In addition, we are required to make technology transfer payments related to training costs of Perupetro professional staff during the exploration phase of $50,000 per year.

On November 21, 2007, we submitted a letter to Perupetro declaring a commercial discovery in the Block Z-1 field. On May 19, 2008 we filed the field development plan with Perupetro. In November 2010, after obtaining an extension of our original proposed First Date of Commercial Production, we placed the Block Z-1 into commercial production.

Royalties under the contract vary from 5% to 20% based on production volumes on the entire Block. Royalties start at 5% if and when production is less than 5,000 Boepd and are capped at 20% if and when production surpasses 100,000 Boepd.

If we decide not to continue with an additional exploration work program beyond the initial exploration work program, we will only be allowed to keep each field discovered and the surrounding five kilometer area for the remainder of the contract life. Currently, we plan to continue our exploration activities to retain the additional area in Block Z-1.

Description of Block XIX and License Contract

Block XIX covers approximately 473,000 gross acres, lying entirely onshore and adjacent to Block Z-1 in northwest Peru. Geologically, the Block lies primarily within the Tumbes Basin of Oligocene-Neogene age, but also covers part of the Talara Basin to the south. Several older wells showed evidence of gas potential in the Mancora formation as well as oil shows from the Heath Formation. The sections of the Tumbes and Talara Basins in Block XIX are primarily exploratory areas and have had limited drilling and seismic activity. However, based on our assessment of available data, we expect the Mancora formation to continue from offshore in Block Z-1 in Piedra Redonda through Block XXIII, also under license to us, and into Block XIX, an area which spans approximately fifty miles.

In December 2003, we signed a license contract whereby we acquired a 100% interest in Block XIX. The term for the exploration period in Block XIX is seven years and can be extended under certain circumstances for an additional period of up to four years. If a commercial discovery is made during the exploration period, the contract will allow for the production of oil for a period of 30 years from the effective date of the contract and the production of gas for a period of 40 years. In the event a block contains both oil and gas, the 40-year term may apply to oil production as well. Royalties under the contract vary from 5% to 20% based on production volumes in the entire Block. Royalties start at 5% if and when production is less than 5,000 Boepd and are capped at 20% if and when production surpasses 100,000 Boepd.

The seven-year exploration phase in the Block XIX License Contract is divided into five periods of 18 months, 24 months, 15 months, 15 months and 12 months, respectively. We are in the fourth exploration period. After satisfying our commitments under the third exploration period by drilling the PLG-1X well in 2011, the fourth exploration period is under suspension while the approval of an environmental impact study by the DGAAE is obtained to conduct a limited 3-D seismic survey. We have received approval from Perupetro to conduct a limited 3-D seismic survey as part of our minimum work commitment for the fourth exploration period to further evaluate future drilling locations. The environmental permit for the additional seismic work was received in August 2014 following the environmental assessment process. The request for approval of the Risk Assessment and Contingency Plan is underway. The fourth exploration phase expires in September 2015.

As of December 31, 2014, we had a $585,000 bond posted for $176,000 in cash collateral as required under the License Contract. The fifth exploration period will require a performance bond of $585,000. The performance bond amounts are not cumulative, and will be released at the end of each exploration period if the work commitment for that period has been satisfied. In addition, we are required to make technology transfer payments related to training costs of Perupetro professional staff during the exploration phase in the amount of $5,000 per year. We must declare a commercial discovery no later than the end of the last exploration period, including any extensions or deferments in order to retain the block.

Under the terms of the Block XIX License Contract, we are required to relinquish 20% of the least promising licensed acreage by the end of the fourth exploration period. Accordingly, we intend to retain the most promising acreage identified. At the end of the exploration phase, we may keep the remainder of the contract area, provided we commit to pursue and implement an additional work program every two years, for up to a maximum of four years. The additional exploration commitment requires us to drill one exploratory well, or conduct certain exploratory working equivalent units, every two years, for up to a maximum period of four years, in order to keep the remaining contract area. If we decide not to continue this minimum work program, we will only be allowed to keep the area over the fields discovered, plus a technical security zone around those areas.

Description of Block XXII and License Contract

On November 21, 2007, we signed a license contract whereby we acquired a 100% interest in Block XXII. Block XXII is located onshore in northwest Peru within the Lancones Basin of Cretaceous—Upper Eocene Age and covers an area of approximately 912,000 gross acres. The Lancones Basin, which includes the Muerto play, is primarily an exploratory area and has had limited drilling and seismic activity. The southern sector of this Block also covers the productive Talara basin of northwest Peru, near the Talara Refinery. The exploration period of the License Contract extends over a seven-year period divided into five periods of four periods of 18 months and a final period of 12 months. Under certain circumstances, the exploration periods may be extended for an additional period of up to three years. We are in the second exploration period and are currently awaiting the approval of an environmental impact study by the DGAAE in order to drill an exploratory well. We plan to drill exploratory wells after receipt of the necessary environmental permits. The timing of the actual drilling in Block XXII will depend on approval of the environment assessment, which is underway, and subsequent receipt of the necessary ancillary permits. Once approval is obtained, we will reestablish timelines for the remaining exploration periods. Drilling of the well in Block XXII is expected in 2016. In each subsequent period after the first 18 month period, we are required to drill an exploratory well or perform other equivalent work commitments. If a commercial discovery is made during the exploration period, the contract will allow for the production of oil for a period of 30 years from the effective date of the contract and the production of gas for a period of 40 years. In the event a block contains both oil and gas, the 40-year term may apply to oil production as well. Royalties under the contract vary from 15% to 30% based on production volumes in the entire Block. Royalties start at 15% if production is less than 5,000 Boepd and are capped at 30% if production surpasses 100,000 Boepd.

In connection with the second exploration period, we were required to obtain a $650,000 performance bond that is secured by cash collateral in the amount of $195,000. Performance bond amounts are not cumulative, and will be released at the end of each exploration period if the work commitment for that period has been satisfied.

Under the Block XXII License Contract, we are required to relinquish at least 20% of the least prospective licensed acreage at the end of the third period and at least another 30% of the least prospective licensed acreage at the end of the fourth period such that at the end of the fourth period, we will have released 50% of the original agreement area. Accordingly, we intend to retain the most prospective acreage identified. The contract does not call for any additional relinquishment of acreage within the contract area and we may retain the remaining un-relinquished area for the remainder of the contract life provided we continue executing a minimum work program as defined under the License Contract. If we decide not to continue this minimum work program, we will only be allowed to keep the fields discovered and the surrounding five kilometer areas for the remainder of the contract life.

Description of Block XXIII and License Contract

On November 21, 2007, we signed a license contract whereby we acquired a 100% interest in Block XXIII, which consists of approximately 230,000 gross acres and is located onshore in northwest Peru between Blocks Z-1 and XIX. This Block is located in the Tumbes Basin, although in its southern section, the Talara Basin, sediments may be found deeper. The sections of the Tumbes and Talara

Basins in Block XXIII are primarily exploratory areas and have had limited drilling and seismic activity. The exploration period of the License Contract extends over a seven-year period divided into two periods of 18 months and two periods of 24 months. We are in the second exploration period. We are required to complete 678 exploration work units which will determine the number of wells drilled in the second exploration period. We spudded an exploration well, the Caracol 1X, on January 5, 2014. This was the first of three exploratory wells drilled in Block XXIII in 2014. The depth of the Caracol 1X well is approximately 3,500 feet. The Cardo 2X exploratory well was spud in late March 2014, and reached a total depth of 3,800 feet in April 2014. The Piedra Candela 3X exploratory well was spud in late April 2014 and reached a total depth of 3,515 feet in May 2014. The Caracol 1X exploratory well tested dry gas from the Mancora formation, light oil from the Heath formation and dry gas from the Zorritos formation. The Cardo 2X exploratory well and the Piedra Candela 3X exploratory well tested dry gas from the Mancora formation. We are planning to pursue a long-term testing program in these Block XXIII prospects.

We are working on an EIA for future exploration in this Block. A request for modifying the EIA for seismic work is under evaluation by DGAAE.

If a commercial discovery is made during the exploration period, the contract will allow for the production of oil for a period of 30 years from the effective date of the contract and the production of gas for a period of 40 years. In the event the block contains both oil and gas, the 40-year term may apply to oil production as well. Royalties under the contract vary from 15% to 30% based on production volumes in the entire Block. Royalties start at 15% if production is less than 5,000 Boepd and are capped at 30% if production surpasses 100,000 Boepd.

In connection with the second exploration period, we were required to obtain a performance bond of $3.4 million that is secured by cash collateral in the amount of $1.0 million. Performance bond amounts are not cumulative, and will be released at the end of each exploration period if the work commitment for that period has been satisfied.

Under the Block XXIII License Contract, we are required to relinquish 20% of the least prospective licensed acreage at the end of the third period and at least another 30% of the least prospective licensed acreage at the end of the fourth period such that at the end of the fourth period, we will have released 50% of the original agreement area. Accordingly, we intend to retain the most prospective acreage identified. The contract does not call for any additional relinquishment of acreage within the contract area and we may retain the remaining un-relinquished area for the remainder of the contract life provided we continue executing an exploration work program as defined under the License Contract. If we decide not to continue this exploration work program, we will only be allowed to keep the fields discovered and the surrounding five kilometer areas for the remainder of the contract life.

Proved Reserves

Our estimated proved oil reserve quantities were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers. NSAI was chosen based on its knowledge and experience of the region in which we operate. Numerous interpretations and assumptions are made in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Our actual reserves, future rates of production and timing of development expenditures may vary substantially from these estimates. See Item 1A Risk Factors, "*Our reserve estimates depend on many assumptions that may turn out to be inaccurate,*" and "*We may not be able to drill proved undeveloped reserve locations included in our proved oil reserves that are scheduled to be drilled five years from initial disclosure of the related reserves.*" for further information. All of our proved reserves are in the Corvina and Albacora fields. Our net quantities of proved developed and undeveloped reserves of crude oil and standardized measure of future net cash flows are reflected in the table below. For further information about the basis of presentation of these amounts, see the "Supplemental Oil and Gas Disclosures (Unaudited)" under Item 8, "Financial Statements and Supplementary Data" contained herein.

As of December 31, 2014, we owned a 51% working interest in the Corvina and Albacora fields that require Peruvian government royalties of 5% to 20% of revenue depending on the level of production. The effect of these royalty interest payments is reflected in the calculation of our net proved reserves. Our estimate of proved reserves has been prepared under the assumption that our license contract will allow production for the possible 40-year term for both oil and gas, as more fully discussed under "Description of Block Z-1" above.

Net Proved Crude Oil Reserves and Future Net Cash Flows
As of December 31, 2014
Based on Average First Day-of-the-Month Fiscal-Year Prices

	Actual (In MBbls)	Estimated Future Capital Expenditures (In thousands)
Proved Developed Producing	3,888	$ -
Proved Developed Not Producing	317	-
Proved Undeveloped	9,361	128,128
Total	13,566	$ 128,128
Standardized Measure of Discounted Future Net Cash Flows, Discounted @ 10% (in thousands)	$ 416,798	

These estimates are based upon a reserve report prepared by NSAI, independent petroleum engineers. NSAI used internally developed reserve estimates and criteria in compliance with the SEC guidelines based on data provided by us. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates," "Management's Discussion and Analysis of Financial Condition and Results of Operations – Proved Reserves," "Management's Discussion and Analysis of Financial Condition and Results of Operations - Standardized Measure of Discounted Future Net Cash Flows" and "Supplemental Oil and Gas Disclosure," in Item 8. "Financial Statements and Supplementary Data." NSAI's report is attached as Exhibit 99.1 to this Form 10-K.

The reserve volumes and values were determined under the method prescribed by the SEC, which requires the use of an average oil price, calculated as the twelve-month first day of the month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Our policies regarding internal controls over the recording of reserves estimates requires reserves to be in compliance with the SEC definitions and guidance.

Our Vice President of Operations is responsible for the reserves recorded and utilizes the reserves estimates made by our third party reserve consultant, NSAI, for the preparation of our reserve report. Our Vice President of Operations has over 30 years of experience in the oil and gas industry, including over 25 years working with Occidental Petroleum in various roles, more recently as Vice President & General Manager for Bolivian operations. Our Vice President of Operations international career includes operational leadership roles in Ecuador, Colombia, Syria, Oman, Yemen, China, and Bangladesh. He holds a Bachelor's degree in Petroleum Engineering and a MBA from the University of Texas, in Austin, Texas.

In addition, the Board of Directors has established a Technical Committee to provide review and oversight of our determination and certification of oil and gas reserves. In providing review and oversight, the Committee may review the propriety of our methodology and procedures for determining the oil and gas reserves as well as the reserves estimates resulting from such methodology and procedures. The Technical Committee may also review the qualifications, independence and performance of our independent reserve engineers.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (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. Dan Paul Smith and Mr. Mike K. Norton. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. Mr. Smith is a Licensed Professional Engineer in the State of Texas (No. 49093) and has over 40 years of practical experience in petroleum engineering, with over 30 years experience in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Norton has been practicing consulting petroleum geology at NSAI since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 34 years of practical experience in petroleum geosciences, with over 24 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Reserve Technologies

The SEC allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. We used a combination of production and pressure performance, wireline wellbore measurements, analytical and simulation studies, offset analogies, seismic data and interpretation, geological data, interpretation, and modeling, wireline formation tests, geophysical logs and core data, and laboratory fluid studies to calculate our reserves estimates.

Development of Proved Reserves

As of December 31, 2014, we had net proved oil reserves of 13.6 MMBbls which represents a decrease from the net proved oil reserves at December 31, 2013 of 16.1 MMBbls. The net proved oil reserves associated with proved developed producing wells increased by 0.7 MMBbls to 3.9 MMBbls in 2014 from 3.2 MMBbls in 2013. Proved developed non–producing reserves increased 0.3 MMBbls to 0.3 MMBbls in 2014 from zero in 2013. The net oil reserves associated with proved undeveloped areas decreased by 3.5 MMBbls to 9.4 MMBbls at December 31, 2014 from 12.9 MMBbls in 2013.

Proved Undeveloped Reserves ("PUD" or "PUDs")

As of December 31, 2014, 9.4 MMBbls of PUDs were reported, a decrease of 3.5 MMBbls from December 2013. The following table shows changes in the PUDs for 2014:

	MBbls
PUDs at January 1, 2014	12,915
Revisions of previous estimates	(1,572)
Purchases of minerals in place	-
Extensions, discoveries and other additions	2,157
Sales of reserves in place	-
Conversion to proved developed reserves	(4,139)

PUDs at December 31, 2014	9,361

In 2014, we had negative revisions to PUDs of 1.4 MMBbls from previous estimates due to performance revisions for the Corvina field.

In 2014, we converted 4.1 MMBbls, or 31.8% of total year-end 2013 PUDs to developed status. As of December 31, 2014, we had a total quantity of 19 PUD locations contributing 9.4 MMBbls to our 2014 proved oil reserves. Of the total 19 PUDs, 13 PUDs are associated with the Corvina field and 6 PUD locations are associated with the Albacora field. Costs incurred to advance the development of PUDs associated with Block Z-1 in 2014 were approximately $127.2 million, of which $124.6 million was funded by our partner in Block Z-1, Pacific Rubiales. Costs incurred to advance the development of PUDs associated with Block Z-1 in 2013 were approximately $70.6 million, which was reimbursed by our partner in Block Z-1, Pacific Rubiales. Costs incurred to advance the development of PUDs associated with Block Z-1 in 2012 were approximately $60.2 million, of which $56.8 million was reimbursed by our partner in Block Z-1, Pacific Rubiales. Costs reimbursed by Pacific Rubiales include the Pacific Rubiales 49% participating interest. As a result of unexpected governmental permitting delays, facilities limitations on the CX-11 offshore platform and contractual and construction issues related to the CX-15 offshore platform, at December 31, 2013, certain PUD locations in Corvina field were included as proved oil reserves that were scheduled to be drilled five years after initial disclosure. In 2014, we completed nine development wells in the Corvina and Albacora fields and converted 31.8% of our 2013 PUD MMBbls to proved developed reserves. The drilling rig is in place and we plan to continue to drill to convert the PUDs. For 2015 we have wells that will be drilled five years after the initial disclosure, the timing of the development of these wells has been changed in conjunction with a shared development plan with our partner in Block Z-1. This shared development plan is not the same drilling plan we initially adopted when we were the sole operator of the Corvina and Albacora fields. The current development plan would result in all PUDs being drilled by 2017.

In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

Production, Average Sales Price and Production Costs.

The following table presents our oil sales volumes, average realized sales prices per Bbl and average production costs per Bbl for the indicated periods.

	Sales (1) Volumes (MBbls)	Average Sales Price	Average Production Cost (2)
2014	923.7	$ 90.36	$ 30.93
2013	506.9	$ 99.79	$ 49.11
2012	1,187.8	$ 103.31	$ 44.16

(1) We inventory our oil that has not been sold. Therefore, per unit costs, after allocating operating costs to inventory, are based on sales volume.

(2) Production costs include the oil production, transportation and workover costs as well as field maintenance and repair costs.

Acreage; Productive Wells

The following table shows the approximate number of developed and undeveloped acres as of December 31, 2014:

	Acres	
	Gross	Net
Developed	800	408
Undeveloped	2,169,200	1,897,642
Total acreage	2,170,000	1,898,050

The number of gross and net productive development wells at December 31, 2014, 2013 and 2012 were 20.0 gross (10.2 net), 13.0 gross (6.6 net) and 11.0 gross (5.6 net), respectively.

Drilling Activity

The number of gross and net productive oil wells drilled in 2014, 2013 and 2012 were 9.0 gross (4.6 net) 2.0 gross (1.0 net) and none, respectively. We drilled three exploratory wells (gross and net) in 2014, the Caracol 1X, the Cardo 2X and the Piedra Candela 3X in Block XXIII, and we plan to pursue a long-term testing program in theses Block XXIII prospects. We did not drill any exploratory wells or have any dry holes in 2013 or 2012. The following lists our successful development wells that were drilled during the year ended December 31, 2014:

Field and Well	Exploratory/Development	Drilling Depth (feet)	Date Objective Drilled/Tested/Completed
Corvina - CX15-2D	Development	8,767	1st quarter
Albacora - A-19D	Development	12,450	1st quarter
Corvina - CX15-3D	Development	7,735	2nd quarter
Albacora - A-21D	Development	12,530	2nd quarter
Corvina - CX15-5D	Development	8,500	3rd quarter
Corvina - CX15-7D	Development	8,314	3rd quarter
Albacora - A-26D	Development	12,700	3rd quarter
Corvina - CX15-10D	Development	8,038	4th quarter
Corvina - CX15-14D	Development	7,845	4th quarter

Successful exploratory and development wells refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated. For the purpose of this table, the term “completed” refers to the installation of equipment for the production of oil or natural gas

The following table shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2014:

Wells in process of drilling or in active completion		**Wells suspended or waiting on completion**	
Exploration	Development (1)	Exploration (2)	Development

Gross	-	2.0	4.0	-
Net	-	1.0	3.5	-

Wells suspended or waiting on completion include exploration and development wells drilling drilling has occurred, but the wells are awaiting resumption of drilling or other completion activities.

(1) Represents the CX15-8D well and the A-27D well.

(2) Represents the CX11-16X well in Block Z-1, the Caracol 1X well, the Cardo 2X well and the Piedra Candela 3X well in Block XXIII.

2015 Activities

Block Z-1

Corvina Field

We spudded the CX15-8D development well in December 2014 and production began in February 2015. We spudded the CX15-9D development well in February 2015.

Albacora Field

We spudded the A-27D development well in October 2014 and production began in January 2015. The A-22D development well was spudded in January 2015.

Delfin Prospect

We have received the permit to install a platform and begin exploratory drilling in the Delfin prospect. Construction of the platform began in the third quarter of 2014. In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Delfin platform and drilling of the Delfin well. We will be storing the platform in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months.

Piedra Redonda Prospect

We have received the permit to install a platform and begin exploratory drilling in the Piedra Redonda prospect. Construction of the platform began in the third quarter of 2014. In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Piedra Redonda platform. We will be storing the platform in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months.

Block Z-1 Seismic

The joint technical team continues to interpret the Block Z-1 3-D seismic data.

Block XIX

We have received approval from Perupetro to conduct a limited 3-D seismic survey as part of our minimum work commitment for the fourth exploration period to further evaluate future drilling locations. The environmental permit for the additional seismic work was received in August 2014 following the environmental assessment process. The request for approval of the Risk Assessment and Contingency Plan is underway.

Block XXII

We have notified Perupetro that the commitment for the second exploration period will be the drilling of one well. The timing of the actual drilling in Block XXII will depend on approval of the environment assessment, which is underway, and subsequent receipt of the necessary ancillary permits. Drilling in Block XXII is expected in 2016.

Block XXIII

We spudded an exploration well, the Caracol 1X, on January 5, 2014. This was the first of three exploratory wells drilled in Block XXIII in 2014. The depth of the Caracol 1X well is approximately 3,500 feet. The Cardo 2X exploratory well was spud in late March 2014, and reached a total depth of 3,800 feet in April 2014. The Piedra Candela 3X exploratory well was spud in late April 2014 and reached a total depth of 3,515 feet in May 2014. The Caracol 1X exploratory well tested dry gas from the Mancora formation, light oil from the Heath formation and dry gas from the Zorritos formation. The Cardo 2X exploratory well and the Piedra Candela 3X exploratory well tested dry gas from the Mancora formation. We are planning to pursue a long-term testing program in these Block XXIII prospects.

We are working on an EIA for future exploration in this Block. A request for modifying the EIA for seismic work is under evaluation by DGAAE.

Marine

In December 2013, we entered into a Management Services Agreement with a third party marine operator to manage our marine fleet. We transferred our BPZ Marine S.R.L. employees to the new operator in the fourth quarter of 2013.

Property in Ecuador

Through our wholly-owned subsidiary, SMC Ecuador Inc., a Delaware corporation, and its registered branch in Ecuador, we also own a 10% non-operating net profits interest in an oil and gas producing property, Block 2, located in the southwest region of the Santa Elena Property. The Santa Elena Property (operated by Pacifpetrol) is located west of the city of Guayaquil along the coast of Ecuador. Almost 3,000 wells have been drilled in the field since production began in the 1920s. There are approximately 1,300 active wells which produce approximately 1,300 barrels of oil per day. The majority of the wells produce intermittently by gas lift, mechanical pump or swabbing techniques. Crude oil is gathered in holding tanks and pumped via pipeline to an oil refinery in the city of Libertad, Ecuador. In May 2013, the license agreement and operating agreement covering the property were extended from May 2016 to December 2029.

In 2013, in order to extend the term of the contract from 2016 to 2029, the Consortium, which includes us and three other partners, agreed to additional work commitments to increase production in the Santa Elena field. Our total share of this commitment over the remaining life of the contract is $4.8 million (our 10% non-operating net profits interest) which amount is due throughout the period of 2015 through 2028. This commitment is expected to be funded by cash on hand, cash generated from new production, or loans of the Consortium. If the Consortium does not have sufficient cash on hand, we may elect to make a cash contribution to the Consortium for our 10% share of the commitment. If we elect not to make our 10% share contribution of the commitment, we would lose our rights in the Consortium and the contract for the Santa Elena field.

In the fourth quarter of 2014, the Consortium incurred a loan for the additional work commitments to increase production in the Santa Elena field. The Consortium loan is to be paid with cash generated from the production of the Santa Elena Field. Our total share of this loan would be $1.0 million (our 10% non-operating net profits interest) which amounts are due quarterly through the fourth quarter of 2017. If the Consortium does not have sufficient cash on hand, we would make a cash contribution to the Consortium for our 10% share of this loan.

ITEM 3. LEGAL PROCEEDINGS

Legal Proceedings Related to the Chapter 11 Case

On March 9, 2015, BPZ Resources, Inc. filed a voluntary petition in the United States Bankruptcy Court for the Southern District of Texas Victoria Division (the "Bankruptcy Court") seeking relief under the provisions of Chapter 11 of Title 11 of the United States Bankruptcy Code (the "Bankruptcy Code"). The Chapter 11 case is being administered under the caption *In re BPZ Resources, Inc.*, Case No. 15-60016 (the "Chapter 11 Case"). The Company will continue to operate its business as "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. As a result of the filing, attempts to collect, secure, or enforce remedies with respect to pre-petition claims against the Company are subject to the automatic stay provisions of section 362 of the Bankruptcy Code. None of the Company's direct or indirect subsidiaries has filed for reorganization under Chapter 11 and none are expected to file for reorganization or protection from creditors under any insolvency or similar law in the U.S. or elsewhere. The Chapter 11 Case is discussed in greater detail in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Voluntary Reorganization Under Chapter 11" and Item 8. "Financial Statements and Supplementary Data," Note-2 "Liquidity and Capital Resources" to our Consolidated Financial Statements included herein.

Other Legal Proceedings

From time to time, the Company may become a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, the Company is not currently a party to any proceeding that it believes could have a potentially material adverse effect on its financial condition, results of operations or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable**.**

Part II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, AND RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our common stock, no par value, is listed on the New York Stock Exchange ("NYSE") and on the Bolsa de Valores Exchange in Lima, Peru (BVL) under the symbol "BPZ." However, on March 2, 2015, we were notified by the NYSE that the staff of NYSE Regulation, Inc. ("NYSE Regulation") had determined to commence proceedings to delist our common stock from the NYSE, as our share price was "abnormally low" pursuant to Section 802.01D of the NYSE Listed Company Manual. Trading of our common stock on the NYSE was suspended immediately. From March 3, 2015 through March 11, 2015, the Company traded under the symbol "BPZR," Currently, the Company is traded under the symbol "BPZRQ."

The following table sets forth, for the periods indicated, the high and low prices of a share of our common stock as reported on the NYSE.

	High	Low
2014		
Fourth quarter	$ 1.92	$ 0.17
Third quarter	3.23	1.91
Second quarter	3.40	2.42
First quarter	3.20	1.76
2013		
Fourth quarter	$ 2.28	$ 1.58
Third quarter	2.55	1.75
Second quarter	2.52	1.67
First quarter	3.33	2.19

Holders

As of February 28, 2015, we had approximately 120 shareholders of record, and an estimated 12,000 beneficial owners of our common stock.

Dividends

We have never paid cash or other dividends on our stock.

For the foreseeable future, we intend to retain earnings, if any, to meet our working capital requirements and to finance future operations. Accordingly, we do not plan to declare or distribute cash dividends to the holders of our common stock in the foreseeable future.

Purchases of Equity Securities By the Issuer and Affiliated Purchasers

As of the date of this filing, we have not repurchased any of our equity securities and have not adopted a stock repurchase program.

Securities Authorized for Issuance Under Equity Compensation Plans

For information regarding securities authorized for issuance under equity compensation plans, see Note-14 — "Stockholders' Equity" of the Notes to Consolidated Financial Statements in Item 8 herein.

Performance Graph

The following graph compares the cumulative total shareholder return for our Common Stock to that of (i) the Russell 2000 Stock Index and (ii) a customized peer group. The companies included in the customized Peer Group Composite, adjusted for the effects of industry consolidation, are Endeavor International Corp., Abraxas Petroleum Corp., Harvest Natural Resources, Inc., Callon Petroleum Co., PetroQuest Energy, Inc., Apco Oil and Gas International Inc., Vaalco Energy, Inc., Contango Oil & Gas Co., and Gran Tierra Energy Inc. “Cumulative total return” is defined as the change in share price during the measurement period, plus cumulative dividends for the measurement period (assuming dividend reinvestment), divided by the share price at the beginning of the measurement period. The graph assumes $100 was invested on January 1, 2009 in our Common Stock, the Russell 2000 Stock Index and the Peer Group Composite.

	2009	2010	2011	2012	2013	2014
BPZ Resources, Inc.	$ 100	$ 50	$ 30	$ 33	$ 19	$ 3
Russell 2000 Stock Index	100	125	118	136	186	193
Peer Group Composite	100	171	178	95	99	64

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operation" and the consolidated financial statements and the notes thereto included under Item 8. – "Financial Statements and Supplementary Data."

	For the Year Ended December 31,				
Operating Results:	**2014**	**2013**	**2012**	**2011**	**2010**
	(In thousands, except per share and per barrel information)				
Total net revenue	$ 83,897	$ 50,729	$ 122,958	$ 143,740	$ 110,464
Operating and administrative expenses:					
Lease operating expense	28,571	24,893	52,458	50,792	32,585
General and administrative expense	23,730	24,111	28,705	34,998	32,444
Geological, geophysical and engineering expense	3,773	2,184	43,787	12,917	19,318
Dry hole costs	-	-	-	13,082	32,778
Depreciation, depletion and amortization expense	23,221	27,214	45,873	38,944	33,755
Standby costs	-	4,311	5,340	4,529	7,487
Other operating expense	4,277	4,430	2,266	-	12,889
Asset impairments	58,000	-	-	-	-
Gain on divestiture	-	-	(26,864)	-	-
Total operating and administrative expenses	141,572	87,143	151,565	155,262	171,256
Operating loss	(57,675)	(36,414)	(28,607)	(11,522)	(60,792)
Other income (expense):					
Income from investment in Ecuador property, net	217	152	62	412	740
Interest expense	(18,670)	(16,158)	(16,115)	(19,772)	(11,618)
Loss on extinguishment of debt	(1,245)	(7,222)	(7,318)	-	-
Gain (loss) on derivatives	2	242	(2,610)	(2,046)	-
Interest income	790	182	44	453	272
Other income (expense)	(351)	(4,268)	(159)	1,083	19
Total other expense	(19,257)	(27,072)	(26,096)	(19,870)	(10,587)
Loss before income taxes	(76,932)	(63,486)	(54,703)	(31,392)	(71,379)
Income tax expense (benefit)	30,974	(5,775)	(15,614)	2,435	(11,608)
Net loss	$ (107,906)	$ (57,711)	$ (39,089)	$ (33,827)	$ (59,771)

Basic and diluted net loss per share	$ (0.93)	$ (0.50)	$ (0.34)	$ (0.29)	$ (0.52)
Basic and diluted weighted average common shares outstanding	116,311	115,943	115,631	115,367	114,919
Oil sales price per barrel, net	$ 90.36	$ 99.79	$ 103.31	$ 101.01	$ 72.53
Operating cost per barrel	$ 30.93	$ 49.11	$ 44.16	$ 36.82	$ 21.47
Balance Sheet Data:					
Working Capital/(Deficit)	$ (166,100)	$ 71,670	$ 58,839	$ 49,180	$ 22,703
Property, equipment and construction in progress, net	165,971	217,753	238,557	381,602	342,507
Total assets	291,360	406,749	527,430	537,333	470,307
Current maturity of long-term debt	214,312	-	24,046	16,854	4,180
Total long-term debt	-	206,939	197,160	248,384	156,750
Stockholders' equity	33,398	137,475	186,300	222,452	251,326
Cash Flow Data:					
Cash flow provided by (used in) operating activites	31,195	(52,627)	(46,062)	47,121	(5,125)
Cash flow provided by (used in) investing activities	(26,283)	53,968	(65,838)	(93,883)	(158,104)
Cash flow provided by (used in) financing activities	(158)	(27,486)	137,268	93,182	156,834

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our audited consolidated financial statements and related notes contained elsewhere in this report. The following discussion includes forward-looking statements that reflect our plans, estimations and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this report.

Introduction

We are an independent oil and gas company focused on the exploration, development and production of oil and natural gas in Peru and Ecuador. We also intend to utilize part of our planned future natural gas production as a supply source for the development of a gas-fired power generation facility in Peru, which may be wholly– owned or partially-owned, or may be wholly-owned by a third party. We have the license agreements for oil and gas exploration and production covering approximately 2.2 million gross (1.9 million net) acres in four blocks in northwest Peru and off the northwest coast of Peru in the Gulf of Guayaquil. We also own a 10% non-operating net profits interest in an oil and gas producing property, Block 2, located in the southwest region of Ecuador.

Voluntary Reorganization Under Chapter 11

We have not been profitable since we commenced operations and we require substantial capital expenditures as we advance development projects at Block Z-1 and exploration projects in our other Blocks. Currently, we require additional financing to continue to fund our capital expenditure program and implement our business plan. Our major sources of funding to date have been oil sales, equity and debt financing activities and asset sales. The increased capital costs and debt service costs in the current economic environment for the oil and gas industry have placed a strain on our cash flow from operations and our ability to reduce our debt leverage.

We currently have the following convertible notes outstanding: (i) $59.9 million principal amount of Convertible Notes due 2015 (the “2015 Convertible Notes”), which bear interest semi-annually at a rate of 6.50% per year, and (ii) $168.7 million principal amount of Convertible Notes due 2017 (the “2017 Convertible Notes”), which bear interest semi-annually at a rate of 8.50% per year. The 2015 Convertible Notes matured with repayment of approximately $62 million in principal and interest due on March 1, 2015. Our estimated capital and exploratory budget for 2015 calls for us to spend approximately $58.6 million in 2015 on capital and exploratory expenditures, excluding capitalized interest, for our three onshore Blocks in which we hold 100% working interests, and our share of the capital and exploratory expenditures for offshore Block Z-1 required under our Joint Venture Agreement with Pacific Rubiales. The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014 and we are now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

The price of oil per barrel has dropped dramatically, particularly in the fourth quarter 2014 and continuing in the first quarter 2015, by more than half since its high in June 2014. In mid-October 2014, we withdrew our previously announced private placement offer of $150.0 million in senior secured notes due 2019 due to adverse market conditions.

On December 8, 2014, the Company received a notification from the New York Stock Exchange (“NYSE”) that the Company had fallen below the NYSE's continued listing standard relating to minimum share price, which requires a minimum average closing price of $1.00 per share over 30 consecutive trading days. The price has remained well below such threshold and the NYSE subsequently notified us on March 2, 2015 that it had determined to commence proceedings to delist our common stock.

As a result of the aforementioned events and circumstances, in December 2014 we engaged the services of Houlihan Lokey Capital Inc. (the “Advisors”) to assist us in analyzing various strategic alternatives and addressing our liquidity and capital structure, and formed a special committee of the Board of Directors to work with the Advisors. We engaged in discussions with representatives of our various debt holders regarding, among other items, the potential terms under which one or both bond issues could be restructured to provide a capital structure which would allow us to continue developing our oil and gas assets. We have also pursued discussions with other potential investors regarding alternative financing solutions. We decided that it was in the best long-term interest of all stakeholders, both credit and equity holders, to expeditiously address the Company's capital structure with the goal of reducing debt and the cost of capital to position the Company for the future, and on March 2, 2015 announced that we had decided not to pay approximately $62 million in principal and interest due on March 1, 2015 on our 2015 Convertible Notes and to use a 10-day grace period on principal due and a 30-day grace period on interest due to continue discussions with our debt holders.

We were unable to reach a mutually agreeable solution within the grace period for the principal amount due on the 2015 Convertible Notes and elected not to make the approximate $59.9 million in principal payment due at the end of the grace period for principal due. As a result, we are in default under the 2015 Convertible Notes, permitting the trustee for the 2015 Convertible Notes or the holders of at least 25% in aggregate principal amount of the outstanding 2015 Convertible Notes to declare the full amount of the principal and interest thereunder immediately due and payable. If the 2015 Convertible Notes were to be accelerated, an event of default would occur under the indenture for the 2017 Convertible Notes, permitting the trustee or the holders of at least 25% in aggregate principal amount of the outstanding 2017 Convertible Notes to also declare the full amount of the principal and interest thereunder immediately due and payable.

On March 9, 2015 (the “Petition Date”), BPZ Resources, Inc. (the “Debtor”) filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the “Bankruptcy Court”) to provide more time to find an appropriate solution to its financial situation and implement a plan of reorganization aimed at improving its capital structure. The Chapter 11 case is being administered by the Bankruptcy Court as Case No. 15-60016.

The filing of the Chapter 11 case constituted an event of default that triggered repayment obligations under the 2015 Convertible Notes and the 2017 Convertible Notes. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 case, and the creditors’ rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

Since the Petition Date, the Debtor has operated its business as a "debtor-in-possession" pursuant to Sections 1107(a) and 1108 of the Bankruptcy Code, which will allow the Debtor to continue operations during the reorganization proceedings. The Debtor will remain in possession of its assets and properties, and its business and affairs will continue to be managed by its directors and officers, subject in each case to the supervision of the Bankruptcy Court.

None of the Debtor's direct or indirect subsidiaries or affiliates has filed for reorganization under Chapter 11 and none is expected to file for reorganization or protection from creditors under any insolvency or similar law in the U.S. or elsewhere. The Debtor's subsidiaries will continue to operate outside of any reorganization proceedings. We therefore do not expect the Debtor's filing for Chapter 11 protection to impact our license agreements.

On the day after the Petition Date, the Debtor obtained approval from the Bankruptcy Court for a variety of "first day" motions to give the Debtor the authority to take a broad range of actions, including, among others, authority to maintain bank accounts and the cash management system, pay certain employee obligations, post-petitition utilities and other customary relief.

Overview

Our current activities and related planning are focused on the following objectives:

- At Block Z-1 with our joint venture partner, Pacific Rubiales;
    - Continuing the offshore development drilling campaign from the Corvina CX-15 platform and Albacora platform;
    - Optimizing oil production in the Corvina and Albacora fields in Block Z-1;
    - Analyzing the data from the 3-D seismic survey in Block Z-1 to guide further exploration and development activities within the Block; and
    - Exploring the remainder of the Block, starting with the Delfin and Piedra Redonda prospects where we have received the permits to install platforms and begin exploratory drilling;
- Continuing acquisition, processing and interpretation of seismic data to better understand the characteristics and potential of our onshore properties;
- Executing a testing program of our gas discovery in Block XXIII, and planning a drilling program if the testing program warrants;
- Planning and permitting an onshore drilling campaign to explore and appraise Block XXII and meet our applicable license requirements;
- Identifying potential partners for our other operations; and
- Continuing business development efforts for our gas-to-power project to monetize our natural gas resources, which we have identified in the Corvina field but for which no market has yet bee secured and related financing has yet to be obtained.

Our activities in Peru include analysis and evaluation of technical data on our properties, preparation of the exploration and development plans for the properties, meeting requirements under the license contracts, procuring equipment for an extended drilling campaign, obtaining all necessary environmental, technical and operating permits, optimizing current production and obtaining preliminary engineering and design of the power plant and gas processing facilities.

Oil Development

General

We plan to conduct additional drilling activities based in part on an ongoing assessment of economic efficiencies, license contract requirements, likely success and logistical issues such as scheduling, required maintenance and replacement of equipment and consultation with our joint venture partner with respect to Block Z-1. This assessment could result in increased emphasis and activities on a given prospect and conversely, could result in decreased emphasis on a given prospect for a period of time. In particular, we will assess allocation of our current resources among the Corvina, Albacora, and other Block Z-1 prospects and certain onshore prospects as they develop, along with our gas-to-power project.

Further, our ability to produce reserves in the Corvina and Albacora fields depends on our ability to finance our continued operations and get our produced oil to market. Any failure in meeting these requirements could negatively affect our reserves and their value as reported under the Securities and Exchange Commission ("SEC") rules. Therefore, in the evaluation of reserves, we attempt to account for all possible delays we can reasonably predict and their impact on the production forecast and remaining reserves to be produced.

Block Z-1

The Block Z-1 License Contract provides for an initial exploration phase of seven years, and exploration can continue in the exploitation phase for an additional six years (in three two-year periods). Each period has a commitment for exploration activities and requires a financial guarantee to secure the performance of the work commitment during such period. We are in the exploitation phase in Block Z-1 which requires one exploration well or 225 exploration work units in each of the three two-year periods. We received approval from Perupetro for the initial two-year period and have committed to drill an exploratory well. The initial two-year phase was originally set to expire in January 2015, but has been extended to July 2015. At the end of the third two-year period, we will be required by the License Contract to surrender back to Perupetro all unexplored areas in Block Z-1.

Divestiture

On April 27, 2012, we and Pacific Rubiales (together with its subsidiaries) executed a Stock Purchase Agreement under which we formed an unincorporated joint venture with Pacific Rubiales to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the SPA, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of our share of capital and exploratory expenditures in Block Z-1 from the effective date of the SPA, January 1, 2012. In order to finalize the joint venture, Peruvian governmental approvals were needed to allow Pacific Rubiales to become a party to the Block Z-1 License Contract. Until the required approvals were obtained, Pacific Rubiales provided a $65.0 million down payment on the purchase price and other funds which we initially accounted for as loans to continue to fund our Block Z-1 capital and exploratory activities. These amounts were reflected as long-term debt prior to closing the transaction. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

The development of Block Z-1 is subject to the terms and conditions of a Joint Operating Agreement with Pacific Rubiales that governs the legal, technical and operating rights and obligations of the parties with respect to the operation of Block Z-1. Under the agreement, we are the operator and responsible for the administrative, regulatory, government and community related duties, and Pacific Rubiales manages the technical and operating duties in Block Z-1. The Joint Operating Agreement will continue for the term of the License Contract and thereafter until all decommissioning obligations under the License Contract have been satisfied.

At closing, Pacific Rubiales exchanged certain loans along with an additional $85.0 million, plus other amounts due to us or from us under the SPA, for the interests and assets obtained from us under the SPA and under the Block Z-1 License Contract. Proceeds of $150.0 million (less transaction costs of $5.7 million) less the net book value of the assets sold of $117.4 million resulting in a gain on the sale of $26.9 million for the year ended December 31, 2012, which was recognized as a component of operating and administrative expenses in connection with the closing. Due to certain tax benefits resulting from the sale, the after tax gain was $31.1 million.

The transaction provided for an adjustment based upon the collection of revenues ($56.1 million) and the payment of expenses ($32.6 million) and income taxes ($5.2 million) attributable to the properties that took place after the effective date of January 1, 2012 and prior to the closing date, which was December 14, 2012. These amounts were settled by adjusting down $18.3 million of the carry amount.

The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014 and we are now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

At December 31, 2013, the carry amount was $81.3 million.

At December 31, 2014 and December 31, 2013, we reflected $22.5 million and $23.9 million, respectively, as other current liabilities and zero and $16.8 million, respectively, as other non-current liabilities for exploratory expenditures related to Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount is being settled by us and Pacific Rubiales under the terms of the SPA with cash payments under the liability of $14.4 million occurring in 2014.

Corvina Field

We originally began producing oil from the CX-11 platform, located in the Corvina field within the offshore Block Z-1 in northwest Peru, under a well testing program that started on November 1, 2007. The Corvina field was placed into commercial production on November 30, 2010. On the CX-11 platform, we have completed a total of nine gross (4.6 net) oil wells, one of which is currently being used as gas injection and/or water injection well. Produced oil is kept in production inventory until such time as it is delivered to the refinery. The oil is delivered by vessel to storage tanks at the refinery in Talara owned by Petroperu, which is located 70 miles south of the platform.

The CX-15 platform was anchored in the West Corvina field, one mile south of the existing CX-11 platform, in the second half of September 2012. On November 8, 2012, we received an environmental permit from the DGAAE allowing us to begin the drilling and subsequent operation of all production and injection facilities on the CX-15 platform at the Corvina field. We installed three pipelines between the two Corvina platforms and one pipeline from the CX-15 platform to discharge manifold for the floating storage and offloading vessel. We made modifications to the platform monitoring and control systems to facilitate operation of the CX-15 platform. Equipment is tracking platform response to weather and ocean conditions as well as draft. As a precaution, we installed an anchoring system to provide redundancy to the spud can, which anchors the platform.

In July 2013, we spudded the first development well, the CX15-1D, from the CX-15 platform. Production from the CX15-1D well began in October 2013. In September 2014, the CX15-1D well was shut in due to sand intrusion. The well was then evaluated to determine the appropriate work plan. A workover will be scheduled for this well. We spudded the second development well, the CX15-2D, in November 2013. The CX15-2D well was drilled near the existing CX11-18XD well to a measured depth of approximately 9,000 feet. We completed the CX15-2D well in January 2014. Production from the CX15-2D well began in February 2014. We spudded the CX15-3D development well in February 2014 and production began in April 2014. In July 2014, the CX-15-3D well was shut in due to high water production. The well was then evaluated to determine the appropriate work plan. The CX15-3D well returned to production in September 2014. We spudded the CX15-5D development well in April 2014 and production began in July 2014. The CX15-7D development well was spudded in July 2014 and production began in September 2014. The CX15-10D development well was spudded in September 2014 and production began in October 2014. The CX15-14D development well was spudded in October 2014 and production began in December 2014. The CX15-8D development well was spudded in December 2014 and production began in February 2015. The CX15-9D development well was spud in February 2015.

Production at each of the Corvina oil wells has declined differently, partly due to the fact that these wells were completed in different zones and some of the wells encountered mechanical problems. The wells have all initially shown typical solution gas drive behavior which can lead to significant production declines during the first year before leveling off to sustainable rates. We believe these results are influenced by technical/mechanical problems encountered with our initial wells, including unintentional production from intervals in the gas cap; however, it is possible we will see similar production declines with new Corvina wells. We believe that our initiation of gas reinjection into the gas cap is helping to slow production decline rates. The work planned during the development drilling program, as well as the data we plan to collect during this program, should help us to better understand future performance expectations.

Further, our ability to produce indicated reserves in Corvina and in Albacora depends on our ability to finance our continued operations and get our produced oil to market. Any failure in meeting these requirements could negatively affect our indicated reserves and their value as reported in our public filings pursuant to SEC requirements. Therefore, in the evaluation of reserves, we attempt to account for all possible delays we can reasonably predict and their impact on the production forecast and remaining reserves to be produced.

Albacora Field

The Albacora field is located in the northern part of our offshore Block Z-1 in northwest Peru. The current area of interest within the Albacora field is located in water depths of less than 100 feet. We currently have completed a total of nine gross (4.6 net) oil wells, two of which are currently being used as a gas injection or a water injection well. We had been producing oil from the Albacora field from December 2009 through late October 2012 under various extended well testing permits.

Installation of the gas and water reinjection equipment was completed on the Albacora A platform and the equipment was ready for reinjection start up early in the first quarter of 2012. We received the required environmental permit for gas injection on October 29, 2012. The Albacora field is no longer subject to an extended well testing program.

We spudded a development well, the A-18D well, from the A platform in the Albacora field of Block Z-1 in September 2013. This well was completed in December 2013. The A-18D well, which began producing at the end of 2013, was shut-in in late March 2014 due to gas intrusion. The well was sidetracked to a depth of 12,800 feet. The A-18D side track well was completed in September 2014 and production began in September 2014. We also spudded a development well, the A-19D well, from the A platform in the Albacora field of Block Z-1 on January 1, 2014. The A-19D well began production on March 1, 2014. The A-21D development well was spud in early March 2014 and production began in May 2014. In July 2014, the A-21D well was shut in due to high water production. The well was then evaluated to determine the appropriate work plan. The A-21D well returned to production in September 2014. We spudded the A-26D development well in May 2014 and production began in July 2014. The A-27D development well was spudded in October 2014 and production began in January 2015. The A-22D development well was spudded in January 2015.

Piedra Redonda Prospect

We have received the permit to install a platform and begin exploratory drilling in the Piedra Redonda prospect. The Piedra Redonda prospect is located south of the Corvina field. Construction of the platform began in the third quarter of 2014.

In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Piedra Redonda platform. We will be storing the platform in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months.

Delfin Prospect

Also, we have received the permit to install a platform and begin exploratory drilling in the Delfin prospect. The Delfin prospect is located southwest of the Corvina field. Construction of the platform began in the third quarter of 2014.

In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Delfin platform and drilling of the Delfin well. We will be storing the platform in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months.

Block Z-1 Seismic

We completed the 3-D seismic survey in February 2013 and seismic data processing of the area in September 2013 to assess our prospects before conducting further drilling operations, as well as to comply with our exploration commitments under our Block Z-1 License Contract.

The technical team continues to interpret the Block Z-1 3-D seismic data.

Block XIX

We are in the fourth exploration period in Block XIX which requires 117 exploration work units which will determine our exploration commitment for the period. The fourth exploration period expires in September 2015.

We have received approval from Perupetro to conduct a limited 3-D seismic survey as part of our minimum work commitment for the fourth exploration period to further evaluate future drilling locations. The environmental permit for the additional seismic work was received in August 2014 following the environmental assessment process. The Risk Assessment and Contingency Plan has been submitted to the DGAAE for approval.

Block XXII

We are in the second exploration period in Block XXII which requires the drilling of one exploration well.

As a result of the 258 km of 2-D seismic survey completed in 2011, three prospects and one lead have been defined. Evaluation continues and we expect to develop a detailed assessment of each prospect in order to define their technical merit and risk to determine their exploration potential.

We have notified Perupetro that the commitment for the second exploration period will be the drilling of one well. The timing of the actual drilling in Block XXII will depend on approval of the environment assessment, which has been submitted to the DGAAE, and subsequent receipt of the necessary ancillary permits. Drilling in Block XXII is expected in 2016.

Block XXIII

We are in the second exploration period in Block XXIII which requires 678 exploration work units which will determine the number of wells drilled.

In 2011, we acquired approximately 370 square km of 3-D seismic data and 312 km of 2-D seismic data which included certain areas of interest within the Palo Santo region and four other prospects that are a part of the Mancora gas play. The processing of the 3-D and 2-D data of Block XXIII has been completed and evaluated.

The environmental permits for the drilling of several prospects identified by the 2-D and 3-D seismic data acquired in 2011 on Block XXIII were approved in January 2013. We received approval to move the previously agreed drilling locations to conform to the 3-D seismic results.

We spudded an exploration well, the Caracol 1X, on January 5, 2014. This was the first of three exploratory wells drilled in Block XXIII in 2014. The depth of the Caracol 1X well is approximately 3,500 feet. The Cardo 2X exploratory well was spud in late March 2014, and reached a total depth of 3,800 feet in April 2014. The Piedra Candela 3X exploratory well was spud in late April 2014 and reached a total depth of 3,515 feet in May 2014. The Caracol 1X exploratory well tested dry gas from the Mancora formation, light oil from the Heath formation and dry gas from the Zorritos formation. The Cardo 2X exploratory well and the Piedra Candela 3X exploratory well tested dry gas from the Mancora formation. We are planning to pursue a long-term testing program in these Block XXIII prospects.

Marine Operations

In December 2013, we entered into a Management Services Agreement with a third party marine operator to manage our marine fleet. We transferred our BPZ Marine Peru S.R.L. employees to the new operator in the fourth quarter of 2013.

Gas-to-Power Project

Our gas-to-power project entails the planned installation of approximately 10-miles of gas pipeline from the CX-11 platform to shore, the construction of gas processing facilities and a 135 MW net simple-cycle power generation facility. The proposed power plant site is located adjacent to an existing substation near Zorritos and a 220 kilovolt transmission line which is now capable of handling up to 420 MW of power. The existing substation and transmission lines are owned and operated by third parties.

In order to support our proposed electric generation project, we commissioned an independent power market analysis for the region. The Peruvian electricity market is deregulated and power is transported through an interconnected national grid managed by the Committee for Economic Dispatching of Electricity. Based on this study, we believe we will be able to sell, under contract, economic quantities of electricity from the initial 135 MW power plant. The market study also indicates that there may be future opportunities for us to generate and sell significantly greater volumes of power into the Peruvian and possibly Ecuadorian power markets. Accordingly, the revenues from the natural gas delivered to the power plant will be derived from the sale of electricity.

We currently estimate the gas-to-power project will cost approximately $153.5 million, excluding capitalized interest, working capital and 18% value-added tax which will be recovered via future revenue billings. The $153.5 million includes $133.5 million for the estimated cost of the power plant and $20.0 million for the natural gas pipeline. While we have held initial discussions with several potential joint venture partners for the gas-to-power project in an attempt to secure additional financing and other resources for the project, we have not entered into any definitive agreements with a potential partner. In the event we are able to identify and reach an agreement with a potential joint venture partner, we may retain only a minority position in the project, or the power generation facility may be wholly owned by a third party. However, we, along with our Block Z-1 partner, expect to retain the responsibility for the construction and ownership of the pipeline. We have obtained certain permits and are in the process of obtaining additional permits to proceed with the project.

Financing Activities

Convertible Notes due 2017

During the third quarter of 2013, we closed on an offering of an aggregate principal amount of $143.8 million of convertible notes due 2017 which includes the exercise of the underwriter’s option to purchase an additional $18.8 million of the 2017 Convertible Notes in addition to the original offering of $125.0 million. The 2017 Convertible Notes are general senior unsecured obligations and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in the right of payment to all of our existing and future subordinated debt. The 2017 Convertible Notes are subordinate to any of our secured indebtedness we may have to the extent of the value of the assets collateralizing such indebtedness. The 2017 Convertible Notes are not guaranteed by our subsidiaries. In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result, we have $168.7 million principal amount of 2017 Convertible Notes outstanding at December 31, 2014.

The interest rate on the 2017 Convertible Notes is 8.50% per year with interest payments due on April 1st and October 1st of each year. The 2017 Convertible Notes mature with repayment of the $168.7 million principal amount (assuming no conversion) on October 1, 2017.

The conversion rate is 249.5866 shares per $1,000 principal amount (equal to an initial conversion price of approximately $4.0066 per share of common stock). Upon conversion, if conversion is elected by the noteholder, we must deliver, at our option, either (1) a number of shares of our common stock determined as set forth in the Indenture dated September 24, 2013, (2) cash, or (3) a combination of cash and shares of our common stock.

For further information regarding the 2017 Convertible Notes see "Liquidity, Capital Resources and Capital Expenditures" below.

Convertible Notes due 2015

During the first quarter of 2010, we closed on a private offering for an aggregate principal amount of $170.9 million of convertible notes due 2015. The 2015 Convertible Notes are our general senior unsecured obligations and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness. The 2015 Convertible Notes are subordinate to all of our secured indebtedness to the extent of the value of the assets collateralizing such indebtedness. The 2015 Convertible Notes are not guaranteed by our subsidiaries. In September 2013, we repurchased $85.0 million of the aggregate principal amount of the $170.9 million of the 2015 Convertible Notes leaving a principal balance of $85.9 million of the 2015 Convertible Notes outstanding. In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result, we have $59.9 million principal amount of 2015 Convertible Notes outstanding at December 31, 2014.

For further information regarding the 2015 Convertible Notes see "Liquidity, Capital Resources and Capital Expenditures" below.

Future Market Trends and Expectations

Our business depends primarily on the level of current and future oil and gas demand and prices which may impact our ability to raise capital to finance the development of our current and future oil and gas opportunities, to continue developing our gas-to-power project, which anchors our gas monetizing strategy, and to maintain our commitments and obligations under our current license contracts. The world economies are continuing on the path to recovery, though at a gradual pace, with a number of regions in the world showing mixed results. Growth has resumed, but is modest and the downside risks remain significant. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

Geopolitical activities across the globe will also have an impact on oil prices. Unrest and conflicts in the world, including the Middle East, with the Syrian uprisings, as well as instability in North Africa, particularly in Egypt, will continue to contribute the volatility of global oil prices.

Oil supply will also play a significant role in price volatility. The significant oil production capacity of Saudi Arabia, and their desire to maintain market share, is a factor influencing the global price of oil. In addition, new North American supply increases have driven down the U.S. crude imports. The impact of a continued increase of U.S. crude oil production will also contribute to putting pressure on global oil prices. The U.S. Energy Information Administration estimates that in 2014 the increase in the global supply of petroleum and other liquid fuels was nearly twice the increase in consumption, leading to lower prices and shrinking profits for oil producers. However, Peru continues to be a net importer of oil.

In response to our current economic environment, for 2015, we will continue to focus on oil development and exploration in Block Z-1 with our Block Z-1 partner, specifically development in the Corvina and Albacora fields and preparing for exploration in the Delfin and Piedra Redonda prospects, as well as onshore drilling campaigns to explore and appraise our other Blocks, as our available funds allow.

From a production perspective, our goal is to increase production during 2015 based on what is expected to be a multi-year drilling program from the CX-15 and Albacora platforms, while gearing up to explore some of the other Block Z-1 prospects.

Expected operational cash flow from Corvina and Albacora oil sales should contribute towards funding the 2015 capital expenditures budget. In addition, we will continue to evaluate our options on additional financing as needed taking into consideration our current reorganization of BPZ Resources, Inc. under Chapter 11 of the U.S. Bankruptcy Code. We anticipate future results will be based on our production levels, current and future oil prices and the outcome of the reorganization. When forecasting our 2015 performance, we relied on assumptions about the market for oil, our customers and suppliers, past results and operational and regulatory delays. We continue to be conservative in view of oil pricing, though there are forecasts both above and below what we would assume for the average spot price. Our results could materially differ from what we anticipate if any of our assumptions, such as major technical or mechanical well issues, commodity pricing, or production levels prove to be incorrect. In addition, our businesses' operations, financial condition and results of operations are subject to numerous risks and uncertainties that, if realized, could cause our actual results to differ substantially from our forward-looking statements. These risks and uncertainties are further described in Item 1A. — "Risk Factors" of this report.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase/ (Decrease)
Net sales volume:	(in thousands except per bbl information)		
Oil (MBbls)	924	507	417
Net revenue:			
Oil revenue, net	$ 83,464	$ 50,585	$ 32,879
Other revenue	433	144	289
Total net revenue	83,897	50,729	33,168
Average sales price (approximately):			
Oil (per Bbl)	$ 90.36	$ 99.79	$ (9.43)
Operating and administrative expenses:			
Lease operating expense	28,571	24,893	3,678
General and administrative expense	23,730	24,111	(381)

Geological, geophysical and engineering expense		3,773		2,184		1,589
Depreciation, depletion and amortization expense		23,221		27,214		(3,993)
Standby costs		-		4,311		(4,311)
Other operating expense		4,277		4,430		(153)
Asset impairments		58,000		-		58,000
Total operating and administrative expenses	$	141,572	$	87,143	$	54,429
Operating loss	$	(57,675)	$	(36,414)	$	(21,261)

Net Oil Revenue

For the year ended December 31, 2014, our net oil revenue increased by $32.9 million to $83.5 million from $50.6 million for the same period in 2013. The increase in net oil revenue is due to an increase in the amount of oil sold of 417 MBbls, partially offset by a decrease of $9.43, or 9.4%, in the average per barrel sales price received. Total sales for the year ended December 31, 2014 were 924 MBbls compared to 507 MBbls for the same period in 2013.

The increase in amount of oil sold for the year ended December 31, 2014 compared to the same period in 2013 is due to increased production in the Albacora field from the A-18D, A-19D, A-21D and A-26D wells and increased production from the CX-15 platform from the CX15-1D, CX15-2D, CX15-3D, CX15-5D, CX15-7D, CX15-10D and CX15-14D wells. We expect net oil revenues to decrease in 2015 from lower crude oil prices in 2015 compared to 2014 despite increased sales volumes from our development drilling program in Block Z-1 that began in the second half of 2013.

The 2014 price/volume analysis is as follows:

		(in thousands)
2013 Oil revenue, net	$	50,585
Changes associated with sales volumes		41,595
Changes associated with prices		(8,716)
2014 Oil revenue, net	$	83,464

For the year ended December 31, 2014, the increase in oil production is due to increased production in the Albacora field as the A-18D, A-19D, A-21D and A-26D wells contributed to production volumes during 2014. At the Corvina field, the declines in production from the wells at the CX-11 platform were more than offset by the new production from the CX-15 platform's CX15-1D, CX15-2D, CX15-3D, CX15-5D, CX15-7D, CX15-10D and CX15-14D wells. Total oil production for the year ended December 31, 2014 was 941 MBbls compared to 514 MBbls for the same period in 2013.

The revenues above are reported net of royalties owed to the government of Peru. Royalties are assessed by Perupetro as stipulated in the Block Z-1 License Agreement based on production levels.

The following table is the amount of royalty costs of approximately 5% of gross revenues for the year ended December 31, 2014 and 2013:

	2014	2013
	(in thousands)	
Royalty costs	$ 4,674	$ 2,707

	$ 4,674	$ 2,707

Other Revenue

For the year ended December 31, 2014, other revenue increased $289,000 to $433,000 from $144,000 for the same period in 2013.

During the year ended December 31, 2014 and December 31, 2013, we recognized other revenue associated with the chartering of support vessels.

Lease Operating Expense

Lease operating expenses include costs incurred to operate and maintain wells and related equipment and facilities, as well as crude oil transportation and inventory changes. These costs include, among others, workover expenses, maintenance and repairs expenses, operator fees, processing fees, insurance and transportation expenses.

For the year ended December 31, 2014, lease operating expenses increased by $3.6 million to $28.6 million ($30.93 per Bbl) from $25.0 million ($49.11 per Bbl) for the same period in 2013. The increase of $3.6 million is due to higher crude oil transportation expense of $6.7 million resulting from higher crude oil sales, higher fuel costs of $2.3 million and higher supply costs of $1.1 million due to increased activity in the Corvina and Albacora fields, partially offset by workover expenses decreasing $5.3 million due to no major workovers performed in 2014 compared to one major workover in 2013, lower costs of $1.0 million associated with the change in oil inventory for the year ended December 31, 2014 compared to the change in oil inventory for the year ended December 31, 2013, and lower other lease operating expenses of $0.2 million. We expect lease operating expense to increase in 2015 due to increased production in Block Z-1 as a result of our development drilling program that began in the second half of 2013.

General and Administrative Expense

General and administrative expenses are overhead-related expenses, including employee compensation, legal, consulting and accounting fees, insurance, and investor relations expenses.

For the year ended December 31, 2014, general and administrative expenses decreased by $0.4 million to $23.7 million from $24.1 million for the same period in 2013. Stock-based compensation expense, a subset of general and administrative expenses, was $3.2 million for the year ended December 31, 2014 and $2.8 million for the same period in 2013. Other general and administrative expenses decreased $0.8 million to $20.5 million for the year ended December 31, 2014 compared to $21.3 million for the same period in 2013. The $0.8 million decrease is due to lower salary and related costs of $2.9 million due to fewer employees and lower other general and administrative expenses of $0.6 million, partially offset by a $1.4 million increase due to higher indirect charges from our Block Z-1 partner and a higher ship management fee of $1.3 million. We expect our 2015 general and administrative expenses to be lower than our 2014 general and administrative expenses given our cost reduction efforts put in to place under a lower crude oil price scenario.

Geological, Geophysical and Engineering Expense

Geological, geophysical and engineering expenses include laboratory, environmental and seismic acquisition related expenses.

For the year ended December 31, 2014, geological, geophysical and engineering expenses increased $1.6 million to $3.8 million compared to $2.2 million for the same period in 2013. This increase is due to higher consulting, salaries and software costs.

Our share of the 2014 and 2013 Block Z-1 exploratory expenditures was fully funded by our partner under the carry agreement in place.

We expect our 2015 geological, geophysical and engineering expense to decrease compared to our 2014 geological, geophysical and engineering expense for Blocks Z-1, XIX, XXII and XXIII as we work to contain all costs under the lower crude oil price environment.

Dry Hole Costs

There were no dry hole costs for the year ended December 31, 2014 or December 31, 2013.

Depreciation, Depletion and Amortization Expense

For the year ended December 31, 2014, depreciation, depletion and amortization expense decreased $4.0 million to $23.2 million from $27.2 million for the same period in 2013. We expect depreciation, depletion and amortization expense in 2015 to decrease from depreciation, depletion and amortization expense in 2014.

For the year ended December 31, 2014, depletion expense decreased $3.2 million to $14.8 million from $18.0 million during the same period in 2013. Depletion decreased in both periods due to capital costs in Block Z-1 reimbursed under the Carry Agreement with Pacific Rubiales and reserves added to the depletion base in 2014.

For the year ended December 31, 2014, depreciation expense decreased $0.8 million to $8.4 million compared to $9.2 million for the same period in 2013.

Standby Costs

For the year ended December 31, 2014, we incurred no standby costs.

For the year ended December 31, 2013, we incurred $4.3 million in standby rig costs.

During 2013, we had the Petrex-10 rig partially or fully on standby for approximately three months and two rigs, the Petrex-28 rig and Petrex-21 rig, partially or fully on standby for approximately five months.

In 2015 we have agreed with our Block Z-1 partner and Perupetro to delay the installation of the Delfin and Piedra Redonda platforms and drilling of the Delfin well. We will be storing the platforms in the Gulf Island yards in Houma, Louisiana for a period of approximately twelve to eighteen months. We will incur preparation, storage, and other charges of approximately $3.0 million to $4.0 million for our share of these costs in 2015.

Other Operating Expense

For the year ended December 31, 2014, we reported $4.3 million of charges in the Consolidated Statements of Operations as “Other operating expense.” We expensed these previously capitalized amounts related to marine operations, a drilling site location and certain equipment and associated capitalized interest as we do not see a future economic benefit in these costs.

For the year ended December 31, 2013, we reported $4.4 million of charges in the Consolidated Statements of Operations as “Other operating expense.” We expensed these costs related to historical pre-development drilling studies for drilling locations and platform technologies and associated capitalized interest as we believe that these locations and technologies may change and we do not see a future value for these studies.

Asset Impairments

For the year ended December 31, 2014, we incurred impairments of $58.0 million related to our power plant and related equipment, using a fair value approach. Using a probability weighted income approach of different courses of action available to us for use of the power plant and related equipment to determine fair value, the assets were impaired for the difference between the carrying value of the assets and the result of the probability weighted discounted cash flows.

For the year ended December 31, 2013, we had no asset impairments.

Gain on Divestiture

For the year ended December 31, 2014 and December 31, 2013, we had no gains on divestitures.

Other Income (Expense)

Other income (expense) includes non-operating income items. These items include interest expense and income, loss on the extinguishment of debt, gains or losses on foreign currency transactions, income and amortization related to the investment in our Ecuador property, as well as gains or losses on derivative financial instruments.

For the year ended December 31, 2014, total other expense decreased $7.8 million to $19.3 million compared to $27.1 million during the same period in 2013.

The change is due to the following:

Interest expense: For the year ended December 31, 2014, we recognized approximately $18.7 million of net interest expense, which included $27.9 million of interest expense reduced by $9.2 million of capitalized interest expense. For the same period in 2013, we recognized $16.2 million in net interest expense, which included $26.1 million of interest expense reduced by $9.9 million of capitalized interest. The increase of $2.5 million in net interest expense is due to higher interest expense of $1.8 million resulting from a higher average interest cost of debt outstanding between the periods and lower interest capitalized of $0.7 million from a lower average construction in progress in the fourth quarter of 2014. In May 2013, we retired the remaining $30.5 million of the $75.0 million secured debt facility and in September 2013 we retired the remaining $36.0 million of the $40.0 million secured debt facility.

Loss on extinguishment of debt: For the year ended December 31, 2014 and December 31, 2013, respectively, we reported $1.2 million and $7.2 million as a loss on extinguishment of debt.

In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result of the exchange during the second quarter of 2014, we incurred a $1.2 million loss.

As a result of the prepayment of the remaining $30.5 million under the $75.0 million secured debt facility during the second quarter of 2013, we incurred $2.4 million of fees and prepayment premium and expensed $1.4 million of unamortized debt issue costs. As a result of the prepayment of the remaining $36.0 million under the $40.0 million secured debt facility during the third quarter of 2013, we incurred $2.0 million of fees and prepayment premium and expensed $1.7 million of unamortized debt issue costs. As a result of the repurchase of $85.0 million of principal amount of the 2015 Convertible Notes during the third quarter of 2013, approximately $12.2 million of the repayment was considered a retirement of debt. We recognized a gain on the retirement of the debt of approximately $0.2 million.

Gain (loss) on derivatives: As a result of the fair value measurement of the Performance Arranger Fees at September 30, 2014 and 2013, respectively, from the measurement at January 1, 2014, and January 1, 2013, respectively, the gain associated with the embedded derivatives decreased $0.3 million to a $2,000 gain for the year ended December 31, 2014 from a $0.3 million gain for the same period in 2013.

Other income (expense): For the year ended December 31, 2014, other income increased $4.6 million to $0.7 million of income compared to $3.9 million loss for the same period in 2013. For the year ended December 31, 2014 and 2013, interest income was $0.8 million and $0.2 million, respectively. For the year ended December 31, 2014 and 2013, foreign currency gains (losses), a component of other income, were ($0.6) million and ($1.2) million, respectively. For the year ended December 31, 2013, expenses of $2.5 million relating to the issuance of the 2017 Convertible Notes were included. There were no similar expenses for the same period in 2014.

Income Taxes

The source of net loss before income tax expense (benefit) for the year ended December 31 is as follows (in thousands):

		2014		2013
United States	$	(47,899)	$	(31,163)
Foreign		(29,033)		(32,323)
Loss before income taxes	$	(76,932)	$	(63,486)

The income tax provision (benefit) for the year ended December 31 consists of the following (in thousands):

		2014		2013
Current Taxes				
Federal	$	-	$	668
Foreign		1,431		2,595
Total Current		1,431		3,263
Deferred Taxes				
Federal		-		-
Foreign		29,543		(9,038)
Total Deferred		29,543		(9,038)
Total income tax expense (benefit)	$	30,974	$	(5,775)

The income tax expense (benefit) for the year ended December 31 differs from the amount computed by applying the U.S. statutory federal income tax rate for the applicable year to consolidated net loss before income taxes as follows (in thousands):

		2014		2013
Federal statutory income tax rate	$	(26,157)	$	(21,585)
Increases (decreases) resulting from:				
Peruvian income tax - rate difference less than 34% statutory		6,694		3,341
Asset impairment		7,767		-
Permanent book/tax differences		1,530		262

Non-deductible intercompany expenses and other	-	(198)
Effect of asset sale with retained oil intangible tax attribute	-	-
Effect of cumulative profit sharing adjustment	-	-
Effect of foreign exchange rate	(126)	(1,462)
Current year foreign withholding tax	1,433	1,690
Change in valuation allowance	39,833	11,509
Uncertain tax positions	-	668
Total income tax expense (benefit)	$ 30,974	$ (5,775)

A summary of the components of deferred tax assets, deferred tax liabilities and other taxes deferred at December 31 are presented below (in thousands):

	2014	**2013**
Deferred Tax:		
Asset:		
Net Operating Loss	$ 80,170	$ 77,588
Deferred Compensation	5,330	4,704
Asset Basis Difference	9,858	9,253
Exploration Expense	15,624	15,836
Depletion	-	-
Asset Retirement Obligation	809	809
Overhead Allocation to Foreign Locations	19,601	10,207
Other	1,342	2,078
Liability:		
Depreciation	(6,429)	(6,272)
Other	-	-
Net Deferred Tax Asset	126,305	114,203
Less Valuation Allowance	(92,308)	(50,601)
Deferred tax asset	$ 33,997	$ 63,602

At December 31, 2014, we had recognized a gross deferred tax asset related to net operating loss carryforwards of $80.2 million before application of the valuation allowances. Net deferred tax assets in the foregoing table include the deferred consequences of the future reversal of Peruvian deferred tax assets and liabilities on the impact of the Peruvian employee profit share plan tax of zero in 2014 and $7.0 million in 2013. For the year ended December 31, 2014, we established a full valuation allowance related to the $6.4 million deferred tax asset applicable to the Peruvian employee profit sharing plan as the more likely than not criteria as to whether the future benefits would be realized was not met.

At December 31, 2014, we had recognized a gross deferred tax asset related to net operating loss carryforwards attributable to the United States of $62.7 million, before application of the valuation allowances. As of December 31, 2014, we had a valuation allowance for the full amount of the domestic deferred tax asset of $50.1 million, resulting from the income tax benefit generated from net losses, as we believe, based on the weight of available evidence, that it is more likely than not that the deferred tax asset will not be realized prior to the expiration of net operating loss carryforwards in various amounts through 2034. Furthermore, because we had no operations within the U.S. taxing jurisdiction, it is likely that sufficient generation of revenue to offset our deferred tax asset is remote.

In 2011, we amended our 2009 U.S. Federal Tax return to elect to deduct our previously benefited foreign income tax credits. This resulted in an increase to our net operating loss carryforward and the elimination of the foreign income tax credit carryforward previously accrued as a deferred tax asset. Since we maintained a full valuation allowance against the net operating loss carryforward and the foreign tax credit carryforward deferred tax assets, the election to deduct the foreign tax credit resulted in no impact to overall tax expense.

At December 31, 2014, we had recognized a gross deferred tax asset related to net operating loss carryforwards attributable to foreign jurisdictions of $17.5 million, before application of the valuation allowances, attributable to foreign net operating losses, which begin to expire in 2015. We are subject to Peruvian income tax on our earnings at a statutory rate, as defined in the Block Z-1 License Contract, of 22%. We assessed our ability to realize the deferred tax asset generated in Peru. We considered whether it is more likely than not that some portion or all of the deferred tax asset will not be realized. The ultimate realization of the deferred tax asset is dependent upon the generation of future taxable income in Peru during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income, the availability of certain prudent and feasible income tax planning opportunities and projections for future taxable income over the periods in which the deferred tax assets are deductible, along with the transition into the commercial phase under the Block Z-1 License Contract, we do not believe it is more likely than not that we will realize all of the deductible differences at December 31, 2014. Therefore, we have recorded a $42.2 million valuation allowance composed of the following:

(1) A $1.9 million valuation allowance on certain foreign deferred tax assets related to overhead allocations and exploration activities on Blocks XIX, XXII and XXIII, as we believe we may not receiv the full benefit of these deductions,
(2) A $15.4 million valuation allowance on the 2011 through 2013 BPZ E&P net operating losses that expire starting in 2015 as we believe we may not receive the full benefit of these deductions,
(3) A $6.7 million valuation allowance on certain BPZ E&P overhead expenses that we believe we may not receive the full benefit of these deductions, and
(4) A $11.8 million valuation allowance on the deferred tax assets of our foreign subsidiary engaging in the development of the gas-to-power project, as we considered it more likely than not that portion or all of the subsidiary's deferred tax assets will not be realized. Further, we will place a valuation allowance on future deferred tax assets of that same foreign subsidiary until we believe is more likely than not the deferred tax assets will be realized.

As a result, we recognized a net deferred tax asset of $34.0 million related to our foreign operations as of December 31, 2014.

We recognized a total tax provision for the year ended December 31, 2014 of approximately $31.0 million. No provision for U.S. federal and state income taxes has been made for the difference in the book and tax basis of our investment in foreign subsidiaries as such amounts are considered permanently invested. Distribution of earnings, as dividends or otherwise, from such investments could result in U.S. federal taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable in various foreign countries. Due to our significant net operating loss carryforward position we have not recognized any excess tax benefit related to our stock compensation plans. ASC Topic 718, "Stock Compensation" ("ASC Topic 718") prohibits the recognition of such benefits until the related compensation deduction reduces the current tax liability.

A reconciliation of the beginning and ending amount of unrecognized tax benefits at December 31 is as follows (in thousands):

	2014	2013
Balance January 1	$ 668	$ -
Additions related to tax positions taken in the current year	-	-

Additions related to tax positions of prior years		47		668
Reductions related to tax positions of prior years		-		-
Reductions related to settlements with taxing authorities		-		-
Reductions related to lapses in statute of limitations		-		-
Balance December 31	$	715	$	668

The December 31, 2014 balance of unrecognized tax benefits includes $0.7 million that, if recognized, would impact our effective income tax rate. Over the next 12 months, we do not anticipate any reduction in the balance. We had accrued interest and penalties related to unrecognized tax benefits of $47,000 and $46,000 as of December 31, 2014 and 2013, respectively. Estimated interest and penalties related to potential underpayment on unrecognized tax benefits, if any, are classified as a component of income tax expense in the Consolidated Statement of Operations.

Net Loss

For the year ended December 31, 2014, our net loss increased $50.2 million to a net loss of $107.9 million, or ($0.93) per basic and diluted share, from a net loss of $57.7 million, or ($0.50) per basic and diluted share, for the same period in 2013.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Year Ended December 31,					
	2013		2012		Increase/ (Decrease)	
Net sales volume:	(in thousands except per bbl information)					
Oil (MBbls)		507		1,188		(681)
Net revenue:						
Oil revenue, net	$	50,585	$	122,708		(72,123)
Other revenue		144		250		(106)
Total net revenue		50,729		122,958		(72,229)
Average sales price (approximately):						
Oil (per Bbl)	$	99.79	$	103.31	$	(3.52)
Operating and administrative expenses						
Lease operating expense		24,893		52,458		(27,565)
General and administrative expense		24,111		28,705		(4,594)
Geological, geophysical and engineering expense		2,184		43,787		(41,603)
Depreciation, depletion and amortization expense		27,214		45,873		(18,659)
Standby costs		4,311		5,340		(1,029)

Other operating expense		4,430		2,266		2,164
Gain on divestiture		-		(26,864)		26,864
Total operating and administrative expenses	$	87,143	$	151,565	$	(64,422)
Operating loss	$	(36,414)	$	(28,607)	$	(7,807)

Net Oil Revenue

For the year ended December 31, 2013, our net oil revenue decreased by $72.1 million to $50.6 million from $122.7 million for the same period in 2012. The decrease in net oil revenue is due to: (1) a decrease in the amount of oil sold of 681 MBbls, and (2) a decrease of $3.52, or 3.4%, in the average per barrel sales price received. Total sales for the year ended December 31, 2013 were 507 MBbls compared to 1,188 MBbls for the same period in 2012.

The decrease in amount of oil sold is due to the December 2012 sale of a 49% participating interest in Block Z-1 to Pacific Rubiales (approximately 582 MBbls for the year ended December 31, 2012) and lower oil production in the Corvina and Albacora fields.

The 2013 price/volume analysis is as follows:

		(in thousands)
2012 Oil revenue, net	$	122,708
Changes associated with sales volumes		(70,341)
Changes associated with prices		(1,782)
2013 Oil revenue, net	$	50,585

For the year ended December 31, 2013, we had consistent oil production from nine gross (4.6 net) producing wells and intermittent production from four gross (2.0 net) wells. During the same period in 2012, we had consistent oil production from seven (3.6 net) producing wells and intermittent production from four (2.0 net) wells. Total oil production for the year ended December 31, 2013 was 514 MBbls compared to 1,185 MBbls for the same period in 2012. The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012 and the entitlement to crude oil production from that day forward was allocated to each partner. The sharing of any production prior to that date was handled as an adjustment to the carry amount under the SPA.

On a pro forma basis, our production for the year ended December 31, 2012 would have been approximately 604 MBbls, assuming the sale of the 49% participating interest in Block Z-1 had closed on January 1, 2012.

The decrease in oil production is due to the December 2012 sale of a 49% participating interest in Block Z-1 to Pacific Rubiales (approximately 581 MBbls for the year ended December 31, 2013) and lower oil production in the Corvina field and in the Albacora field.

The revenues above are reported net of royalties owed to the government of Peru. Royalties are assessed by Perupetro as stipulated in the Block Z-1 License Agreement based on production levels.

The following table is the amount of royalty costs of approximately 5% of gross revenues for the year ended December 31, 2013 and 2012:

	2013	2012
	(in thousands)	
Royalty costs	$ 2,707	$ 6,605
	$ 2,707	$ 6,605

Other Revenue

For the year ended December 31, 2013, other revenue decreased $0.2 million to $0.1 million from $0.3 million for the same period in 2012.

During the year ended December 31, 2013, we recognized other revenue associated with the chartering of support vessels.

During the year ended December 31, 2012, we chartered one vessel to a third party for approximately two weeks in January, and two marine vessels to a third party for approximately one week in September.

Lease Operating Expense

Lease operating expenses include costs incurred to operate and maintain wells and related equipment and facilities, as well as crude oil transportation and inventory changes. These costs include, among others, workover expenses, maintenance and repairs expenses, operator fees, processing fees, insurance and transportation expenses.

For the year ended December 31, 2013, lease operating expenses decreased by $27.5 million to $25.0 million ($49.11 per Bbl) from $52.5 million ($44.16 per Bbl). The decrease is due to a reduction in lease operating expenses of approximately $25.7 million related to the sale of a 49% participating interest in Block Z-1 in December 2012. Additionally, repairs and maintenance expense decreased by $1.7 million due to fewer maintenance and repairs on vessel support services, fuel costs decreased by $1.1 million, contract pumping services decreased by $0.9 million due to reduced rent of hydraulic jet pumps used to assist oil production and other lease operating expenses decreased by $0.3 million. These decreases were offset by higher workover expenses of $2.2 million associated with the one major workover performed in 2013, compared to the one major less expensive workover in 2012.

General and Administrative Expense

General and administrative expenses are overhead-related expenses, including employee compensation, legal, consulting and accounting fees, insurance, and investor relations expenses.

For the year ended December 31, 2013, general and administrative expenses decreased by $4.6 million to $24.1 million from $28.7 million for the same period in 2012. Stock-based compensation expense, a subset of general and administrative expenses, was $2.8 million for the year ended December 31, 2013 and $2.8 million for the same period in 2012. Other general and administrative expenses decreased $4.6 million to $21.3 million from $25.9 million for the same period in 2012. The $4.6 million decrease is due to lower salary and related costs of $1.9 million due to fewer employees, lower non-income taxes of $1.3 million, lower consulting costs of $0.5 million and lower other general and administrative expenses of $0.9 million.

Geological, Geophysical and Engineering Expense

Geological, geophysical and engineering expenses include laboratory, environmental and seismic acquisition related expenses.

The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012 and the carry of exploratory expenditures for Block Z-1 by Pacific Rubiales began that day. Our share of the 2013 Block Z-1 exploratory expenditures was fully funded by our partner under the carry agreement in place.

For the year ended December 31, 2013, geological, geophysical and engineering expenses decreased $41.6 million to $2.2 million compared to $43.8 million for the same period in 2012. The decrease is due to the seismic acquisition activity associated with our seismic data acquisition plan for Block Z-1 that occurred in 2012 compared to the lower activity and funding of seismic expenses in Block Z-1 by Pacific Rubiales in 2013.

Dry Hole Costs

There were no dry hole costs for the year ended December 31, 2013 or December 31, 2012.

Depreciation, Depletion and Amortization Expense

For the year ended December 31, 2013, depreciation, depletion and amortization expense decreased $18.7 million to $27.2 million from $45.9 million for the same period in 2012.

For the year ended December 31, 2013, depletion expense decreased $13.5 million to $18.0 million from $31.5 million during the same period in 2012. The decrease for the year ended December 31, 2013 compared to the same period in 2012 is due to lower production in the Corvina and Albacora fields in 2013 and the sale of a 49% participating interest in the Block Z-1 License Contract in December 2012.

For the year ended December 31, 2013, depreciation expense decreased $5.2 million to $9.2 million compared to $14.4 million for the same period in 2012. The decrease is due to assets included in the sale of a 49% participating interest in the Block Z-1 License Contract in December 2012 and the change in our method of estimating the depreciation of producing equipment to the unit-of-production method from a straight-line five-year life method, partially offset by a change in useful life, as a result of new laws, of two vessels used in our marine operations that is contributing an additional $0.6 million of depreciation expense per quarter which began in the third quarter of 2012 and is expected to continue through December 2014.

Standby Costs

For the year ended December 31, 2013, we incurred $4.3 million in standby rig costs.

During 2013, we had the Petrex-10 rig partially or fully on standby for approximately three months and two rigs, the Petrex-28 rig and Petrex-21 rig, partially or fully on standby for approximately five months.

For the year ended December 31, 2012, we incurred $5.3 million in standby rig costs.

During 2012, we had the Petrex-18 rig, which was previously leased to another operator in 2011, on standby through July 31, 2012. Our contract on this rig was amended and the contract was suspended from August 1, 2012 through April 30, 2013. We had the Petrex-28 rig on standby from September 2012 through December 2012, as we expected to use this rig in drilling operations on the CX-15 platform. Additionally, in 2012, we had a workover rig, the Petrex-10, on standby for two months to allow for seismic acquisition activities where the workover rig was operating.

Other Operating Expense

For the year ended December 31, 2013, we reported $4.4 million of charges in the Consolidated Statements of Operations as “Other operating expense.” We expensed these costs related to historical pre-development drilling studies for drilling locations and platform technologies and associated capitalized interest as we believe that these locations and technologies may change and we do not see a future value for these studies.

For the year ended December 31, 2012, we reported $2.3 million of abandonment charges in the Consolidated Statements of Operations as “Other operating expense.” We accrued $2.3 million of abandonment costs related to a platform in the Piedra Redonda field in Block Z-1, as we are obligated to ensure the offshore platform does not cause a threat to navigation in the area or marine wildlife. The $2.3 million charge is in addition to the Piedra Redonda platform abandonment costs previously recorded in the third quarter of 2010.

Gain on Divestiture

On April 27, 2012, we and Pacific Rubiales (together with its subsidiaries) executed a SPA under which we formed an unincorporated joint venture to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the SPA, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of our share of capital and exploratory expenditures in Block Z-1 from the effective date of the SPA, January 1, 2012. On December 14, 2012, Perupetro approved the terms of the amendment to the Block Z-1 License Contract to recognize the sale of a 49% participating interest in offshore Block Z-1 to Pacific Rubiales. We and Pacific Rubiales waived and modified certain contract conditions in order to close the transaction. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract. The receipt of net proceeds ($150.0 million, less transaction costs of $5.7 million) in excess of the net book value of 49% of Block Z-1 historic assets of $117.4 million resulting in a pre-tax gain of $26.9 million for the year ended December 31, 2012. Tax impacts of this gain are reported under Income Taxes.

There were no similar gains in 2013.

Other Income (Expense)

Other income (expense) includes non-operating income items. These items include interest expense and income, loss on the extinguishment of debt, gains or losses on foreign currency transactions, income and amortization related to the investment in our Ecuador property, as well as gains or losses on derivative financial instruments. For the year ended December 31, 2013, total other expense increased $1.0 million to $27.1 million compared to $26.1 million during the same period in 2012. The increase is due to the following:

Interest expense: For the year ended December 31, 2013, we recognized approximately $16.2 million of net interest expense, which included $26.1 million of interest expense reduced by $9.9 million of capitalized interest expense. For the year ended December 31, 2012, we recognized approximately $16.1 million of net interest expense which includes $31.7 million of interest expense reduced by $15.6 million of capitalized interest expense. The increase of $0.1 million in net interest expense is due to lower capitalized interest of $5.7 million because of lower average construction in progress balances between the two periods as a result of the development of the CX-15 platform and Albacora production and gas injection facilities in 2012, partially offset by lower interest expense of $5.6 million resulting from a lower average of interest bearing debt outstanding between the two periods due to the $40.0 million principal debt prepayment made in May 2012 on the $75.0 million secured debt facility, scheduled principal repayments since March 2012 and the retirement of the remaining $30.5 million of the $75.0 million secured debt facility in May 2013.

Loss on extinguishment of debt: As a result of the prepayment of the remaining $30.5 million under the $75.0 million secured debt facility during the second quarter of 2013, we incurred $2.4 million of fees and prepayment premium and expensed $1.4 million of unamortized debt issue costs. These amounts were recognized as a “Loss on extinguishment of debt” in the Consolidated Statement of Operations. As a result of the prepayment of the remaining $36.0 million under the $40.0 million secured debt facility during the third quarter of 2013, we incurred $2.0 million of fees and prepayment premium and expensed $1.7 million of unamortized debt issue costs. These amounts were recognized as a “Loss on extinguishment of debt” in the Consolidated Statement of Operations. As a result of the repurchase of $85.0 million of principal amount of the 2015 Convertible Notes during the third quarter of 2013, approximately $12.2 million of the repayment was considered a retirement of debt. We recognized a gain on the retirement of the debt of approximately $0.2 million and this gain is included in the “Loss on extinguishment of debt” in the Consolidated Statement of Operations. For the year ended December 31, 2013, we reported $7.2 million as a loss on extinguishment of debt.

As a result of the prepayment and amendment to the $75.0 million secured debt facility during the second quarter of 2012, we incurred $5.8 million of fees and prepayment penalties and $1.1 million of debt issue costs. The $5.8 million in fees and prepayment penalties were recognized as a “Loss on extinguishment of debt” in the consolidated statement of operations of which 25% was paid at the time of the amendment and prepayment and 25% was paid at the time of each of the next three quarterly interest payment dates ending in January 2013. Approximately $1.5 million of the remaining $2.8 million of unamortized debt issue costs associated with the initial loan was expensed as a “Loss on extinguishment of debt” in the consolidated statement of operations when we prepaid $40.0 million of principal. For the year ended December 31, 2012, we reported $7.3 million as a loss on extinguishment of debt.

Gain (loss) on derivatives: In connection with obtaining the $40.0 million and $75.0 million secured debt facilities in January and July 2011, respectively, we entered into performance based arranger fees (“Performance Based Arranger Fee”) that we are accounting for as embedded derivatives. As a result of the fair value measurement at December 31, 2013 and 2012, respectively, from the measurement at January 1, 2013 and January 1, 2012, respectively, the gain associated with the embedded derivatives increased $2.9 million to a $0.3 million gain for the year ended December 31, 2013 from a $2.6 million loss for the same period in 2012.

Investment income: For the year ended December 31, 2013, income from our investment in Ecuador property, net of investment amortization, increased by $0.1 million to income of $0.2 million from income of $0.1 million in 2012. For both periods, the dividends received were $0.3 million. For the year ended December 31, 2013 and 2012, investment income includes amortization expense of approximately $98,000 and $188,000, respectively.

Other income (expense): For the year ended December 31, 2013, other expense increased $4.1 million to $4.3 million compared to $0.2 million in the same period in 2012. For the year ended December 31, 2013, expenses of $2.5 million relating to the issuance of the 2017 Convertible Notes were included. There were no similar expenses for the same periods in 2012. Also, for the year ended December 31, 2013 and 2012, foreign currency losses were $1.2 million and $0.2 million, respectively.

Income Taxes

The source of net loss before income tax expense (benefit) for the year ended December 31 is as follows (in thousands):

	2013	**2012**
United States	$ (31,163)	$ (6,465)
Foreign	(32,323)	(48,238)
Loss before income taxes	$ (63,486)	$ (54,703)

The income tax provision (benefit) for the year ended December 31 consists of the following (in thousands):

	2013	**2012**
Current Taxes		
Federal	$ 668	$ -

Foreign	2,595	13,551
Total Current	3,263	13,551
Deferred Taxes		
Federal	-	-
Foreign	(9,038)	(29,165)
Total Deferred	(9,038)	(29,165)
Total income tax expense (benefit)	$ (5,775)	$ (15,614)

The income tax expense (benefit) for the year ended December 31 differs from the amount computed by applying the U.S. statutory federal income tax rate for the applicable year to consolidated net loss before income taxes as follows (in thousands):

	2013	2012
Federal statutory income tax rate	$ (21,585)	$ (18,599)
Increases (decreases) resulting from:		
Peruvian income tax - rate difference less than 34% statutory	3,341	7,791
Permanent book/tax differences	262	(621)
Non-deductible intercompany expenses and other	(198)	2,763
Effect of asset sale with retained oil intangible tax attribute	-	(15,111)
Effect of cumulative profit sharing adjustment	-	(895)
Effect of foreign exchange rate	(1,462)	(1,678)
Current year foreign withholding tax	1,690	1,699
Change in valuation allowance	11,509	9,037
Uncertain tax positions	668	-
Total income tax expense (benefit)	$ (5,775)	$ (15,614)

A summary of the components of deferred tax assets, deferred tax liabilities and other taxes deferred at December 31 are presented below (in thousands):

	2013	2012
Deferred Tax:		
Asset:		
Net Operating Loss	$ 77,588	$ 57,698
Deferred Compensation	4,704	4,221
Asset Basis Difference	9,253	5,129
Exploration Expense	15,836	14,054
Depletion	-	3,652
Asset Retirement Obligation	809	593
Overhead Allocation to Foreign Locations	10,207	7,476

Other	2,078	2,069
Liability:		
Depreciation	(6,272)	(724)
Other	-	(30)
Net Deferred Tax Asset	114,203	94,138
Less Valuation Allowance	(50,601)	(38,896)
Deferred tax asset	$ 63,602	$ 55,242

At December 31, 2013, we had recognized a gross deferred tax asset related to net operating loss carryforwards of $77.6 million before application of the valuation allowances. Net deferred tax assets in the foregoing table include the deferred consequences of the future reversal of Peruvian deferred tax assets and liabilities on the impact of the Peruvian employee profit share plan tax of $7.0 million in 2013 and $5.8 million in 2012.

At December 31, 2013, we had recognized a gross deferred tax asset related to net operating loss carryforwards attributable to the United States of $57.0 million, before application of the valuation allowances. As of December 31, 2013, we had a valuation allowance for the full amount of the domestic deferred tax asset of $46.8 million, resulting from the income tax benefit generated from net losses, as we believe, based on the weight of available evidence, that it is more likely than not that the deferred tax asset will not be realized prior to the expiration of net operating loss carryforwards in various amounts through 2033. Furthermore, because we had no operations within the U.S. taxing jurisdiction, it is likely that sufficient generation of revenue to offset our deferred tax asset is remote.

At December 31, 2013, we had recognized a gross deferred tax asset related to net operating loss carryforwards attributable to foreign jurisdictions of $20.6 million, before application of the valuation allowances, attributable to foreign net operating losses, which begin to expire in 2014. We are subject to Peruvian income tax on its earnings at a statutory rate, as defined in the Block Z-1 License Contract, of 22%. We assessed our ability to realize the deferred tax asset generated in Peru. We considered whether it is more likely than not that some portion or all of the deferred tax asset will not be realized. The ultimate realization of the deferred tax asset is dependent upon the generation of future taxable income in Peru during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income, the availability of certain prudent and feasible income tax planning opportunities and projections for future taxable income over the periods in which the deferred tax assets are deductible, along with the transition into the commercial phase under the Block Z-1 License Contract, we believe it is more likely than not that we will realize the majority of the these deductible differences at December 31, 2013. In addition, we had a $3.8 million valuation allowance on certain foreign deferred tax assets related to overhead allocations and exploration activities on Blocks XIX, XXII and XXIII, as we believe we may not receive the full benefit of these deductions. As a result, we recognized a net deferred tax asset of $63.6 million related to our foreign operations as of December 31, 2013.

We recognized a total tax provision for the year ended December 31, 2013 of approximately $5.8 million. No provision for U.S. federal and state income taxes has been made for the difference in the book and tax basis of our investment in foreign subsidiaries as such amounts are considered permanently invested. Distribution of earnings, as dividends or otherwise, from such investments could result in U.S. federal taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable in various foreign countries. Due to our significant net operating loss carryforward position we have not recognized any excess tax benefit related to our stock compensation plans. ASC Topic 718, “Stock Compensation” (“ASC Topic 718”) prohibits the recognition of such benefits until the related compensation deduction reduces the current tax liability.

A reconciliation of the beginning and ending amount of unrecognized tax benefits at December 31 is as follows (in thousands):

	2013	2012
Balance January 1	$ -	$ -

Additions related to tax positions taken in the current year	-	-
Additions related to tax positions of prior years	668	-
Reductions related to tax positions of prior years	-	-
Reductions related to settlements with taxing authorities	-	-
Reductions related to lapses in statute of limitations	-	-
Balance December 31	$ 668	$ -

The December 31, 2013 balance of unrecognized tax benefits includes $0.7 million that, if recognized, would impact our effective income tax rate. Over the next 12 months, we do not anticipate any reduction in the balance. We had accrued interest and penalties related to unrecognized tax benefits of $46,000 and none as of December 31, 2013 and 2012, respectively. Estimated interest and penalties related to potential underpayment on unrecognized tax benefits, if any, are classified as a component of income tax expense in the Consolidated Statement of Operations.

Net Loss

For the year ended December 31, 2013, our net loss increased $18.6 million to a net loss of $57.7 million, or ($0.50) per basic and diluted share, from a net loss of $39.1 million, or ($0.34) per basic and diluted share, for the same period in 2012.

Proved Reserves

We are focused on the development and production of our holdings in Peru. Future profitability partially depends on commodity prices and the cost of finding and developing oil and gas reserves. Reserves growth can be achieved through successful exploration and development drilling and improved recovery of producing properties.

Extensions, Discoveries and Other Additions

The 2014 reserve analysis prepared by NSAI included extensions, discoveries and other additions of 2.9 MMBbls, which were due to additional wells drilled in the Albacora field. The 2013 reserve analysis prepared by NSAI included extensions, discoveries and other additions of 0.3 MMBbls, which were due to an additional well drilled in the Albacora field. In 2012, the reserve analysis prepared by NSAI included no extensions, discoveries and other additions.

Revisions of Previous Estimates

The 2014 reserve analysis prepared by NSAI included negative revisions due to performance of 4.5 MMBbls and a $99.65 per barrel price that is lower than the 2013 reserve analysis. The negative revisions due to performance related to the CX15-2D well, CX15-5D well, CX15-10D well, A-18D well and the A-21D well, as well as PUD performance revisions in the Corvina field. The 2013 reserve analysis prepared by NSAI included negative revisions due to performance of 0.1 MMBbls and a $105.32 per barrel price that is lower than the 2012 reserve analysis. The 2012 reserve analysis prepared by NSAI included negative revisions due to performance of 0.7 MMBbls. The negative revisions were due to workovers pending on the 14D and 15D wells at the Corvina CX-11 platform, as well as removal of the Albacora A12F well from the proved category given its required conversion to a gas injection well. The 2012 reserve report used a $108.10 per barrel price.

Sales of Reserves in Place

The 2012 reserve analysis prepared by NSAI included sales in place of 16.4 MMBbls that relate to our sale of a 49% participating interest in Block Z-1. There were no sales of reserves in place in 2014 and 2013.

Proved Undeveloped Reserves

As of December 31, 2014, 9.4 MMBbls of PUDs were reported, a decrease of 3.5 MMBbls from December 31, 2013. The following table shows changes in the PUDs for 2014:

	MBbls
PUDs at January 1, 2014	12,915
Revisions of previous estimates	(1,572)
Purchases of minerals in place	-
Extensions, discoveries and other additions	2,157
Sales of reserves in place	-
Conversion to proved developed reserves	(4,139)
PUDs at December 31, 2014	9,361

In 2014, we had negative revisions to PUDs of 1.4 MMBbls from previous estimates due to performance revisions for the Corvina field.

In 2014, we converted 4.1 MMBbls, or 31.8% of total year-end 2013 PUDs to developed status. As of December 31, 2014, we had a total quantity of 19 PUD locations contributing 9.4 MMBbls to our 2014 proved oil reserves. Of the total 19 PUDs, 13 PUDs are associated with the Corvina field and 6 PUD locations are associated with the Albacora field. Costs incurred to advance the development of PUDs associated with Block Z-1 in 2014 were approximately $127.2 million, of which $124.6 million was funded by our partner in Block Z-1, Pacific Rubiales. Costs incurred to advance the development of PUDs in 2013 were approximately $70.6 million associated with Block Z-1 which was reimbursed by our partner in Block Z-1, Pacific Rubiales. Costs incurred to advance the development of PUDs in 2012 were approximately $60.2 million associated Block Z-1 of which $56.8 million was reimbursed by our partner in Block Z-1, Pacific Rubiales. Costs reimbursed by Pacific Rubiales include the Pacific Rubiales 49% participating interest. As a result of unexpected governmental permitting delays, facilities limitations on the CX-11 offshore platform and contractual and construction issues related to the CX-15 offshore platform, at December 31, 2013, certain PUD locations in Corvina field were included as proved oil reserves that were scheduled to be drilled five years after initial disclosure. In 2014, we completed nine development wells in the Corvina and Albacora fields and converted 31.8% of our 2013 PUD MMBbls to proved developed reserves. The drilling rig is in place and we plan to continue to drill to convert the PUDs. For 2015 we have wells that will be drilled five years after the initial disclosure, the timing of the development of these wells has been changed in conjunction with a shared development plan with our partner in Block Z-1. This shared development plan is not the same drilling plan we initially adopted when we were the sole operator of the Corvina and Albacora fields. The current development plan would result in all PUDs being drilled by 2017.

In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

These estimates are based upon a reserve report prepared by NSAI, independent petroleum engineers. NSAI used internally developed reserve estimates and criteria in compliance with the SEC guidelines based on data provided by us. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates,” and “Supplemental Oil and Gas Disclosure,” in Item 8. “Financial Statements and Supplementary Data.” NSAI’s report is attached as Exhibit 99.1 to this Form 10-K.

Standardized Measure of Discounted Future Net Cash Flows

At December 31, 2014, the discounted estimated future net cash flows after-tax (at 10%) from our proved reserves were $0.4 billion (measured in accordance with the regulations of the SEC and the Financial Accounting Standards Board). This amount was calculated based on the 12-month average beginning-of-month prices for the year, held flat for the life of the reserves. The decrease of $0.3 billion, or 38.5%, in 2014 compared to 2013 is due to negative revisions of previous reserve estimates, a decrease in oil prices and an increase in operating costs. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates" and Item 8. "Financial Statements and Supplementary Data - Supplemental Oil and Gas Disclosure," of this Form 10-K.

The present value of future net cash flows does not purport to be an estimate of the fair value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil.

Liquidity, Capital Resources and Capital Expenditures

At December 31, 2014, we had cash and cash equivalents of $62.1 million, an accounts receivable balance of $1.9 million and a working capital deficit of $166.1 million. At February 28, 2015, we had estimated cash and cash equivalents of $47.0 million.

At December 31, 2014, we had trade accounts payable and accrued liabilities of $10.9 million.

At December 31, 2014, our outstanding debt consisted of the 2015 Convertible Notes whose net amount of $59.5 million includes the $59.9 million of principal reduced by $0.4 million of the remaining unamortized discount and the 2017 Convertible Notes whose net amount of $154.8 million includes the $168.7 million of principal reduced by $13.9 million of the remaining unamortized discount. At December 31, 2014, the current and long-term portions of our long-term debt were $214.3 million and zero, respectively.

	For the Year Ended December 31,		
Cash Flows	**2014**	**2013**	**2012**
		(in thousands)	
Cash provided by (used in):			
Operating activities	$ 31,195	$ (52,627)	$ (46,062)
Investing activities	(26,283)	53,968	(65,838)
Financing activities	(158)	(27,486)	137,268

2014 Operating Activities

Cash provided by operating activities increased by $83.8 million to a source of cash of $31.2 million for the year ended December 31, 2014 from a use of cash of $52.6 million for the same period in 2013. The change in cash flows before changes in operating assets and liabilities provided an increase in the source of cash of $35.0 million due to higher revenues and lower standby costs. Changes in cash flow as a result of changes in operating assets and liabilities provided an increase in the source of cash of $48.8 million. The increase in the source of cash is due to the changes in liabilities (accounts payable of $20.1 million, accrued liabilities of $15.9 million and income taxes payable of $11.9 million (a tax payment made in 2013 on the gain on the sale of a 49% participating interest in Block Z-1 in 2012), partially offset by a change in other liabilities of $17.4 million (representing a payment to our joint venture partner in 2014) providing an increase in the source of cash of $30.5 million. Also providing a source of cash were changes in assets (accounts receivable of $16.5 million, changes in inventory of $2.7 million and changes in other assets of $0.9 million, partially offset by changes in value-added tax receivables of $1.8 million) providing a increase in the source of cash of $18.3 million.

2013 Operating Activities

Cash provided by operating activities decreased by $6.5 million to a use of cash of $52.6 million for the year ended December 31, 2013, from a use of cash of $46.1 million for the same period in 2012. Cash flows in 2013 decreased due to lower oil sales volumes and lower oil prices, partially offset by lower geological, geophysical and engineering expense, as well as the impact of lower lease operating expenses and lower other costs. Changes in cash flow as a result of changes in operating assets and liabilities provided an increase in the use of cash of $17.8 million. The increase in the use of cash is due to: (1) a decrease in the change to accrued and other liabilities balances of $34.9 million; (2) a decrease of $23.6 million in the change of current tax payables as a result of the tax payment on the gain on the sale of a 49% participating interest in Block Z-1 in 2012 of $11.7 million and (3) a decrease in the change to accounts payables of $21.3 million that includes amounts paid to our joint venture partner. Offsetting these uses of cash are changes in operating assets and liabilities providing sources of cash including: (1) a decrease in the change to value-added taxes of $30.8 million as we had a value-added tax recovery in 2013 and had more expenditures subject to value-added taxes; (2) a decrease in the change in accounts receivable due to amounts from our joint venture partner and the timing of oil deliveries and payments for those deliveries of $19.6 million; (3) a decrease in inventory of $7.9 million and (4) a decrease in the change of prepaid and other assets of $3.7 million. Cash flow before changes in operating assets and liabilities provided a decrease in the use of cash of $11.3 million during 2013 compared to 2012.

2014 Investing Activities

Net cash used in investing activities increased by $80.3 million to $26.3 million for the year ended December 31, 2014 from a source of cash of $54.0 million for the same period in 2013. The increase in cash used in investing activities is due to a release of restricted cash of $67.4 million from principal repayments of the $75.0 million secured debt facility and the $40.0 million secured debt facility for the year ended 2013 compared to $3.1 million change in restricted cash for the year ended 2014, and increased capital expenditures of $16.0 million in 2014 due to our development initiatives for the exploration and production of our onshore oil and natural gas properties.

2013 Investing Activities

Net cash provided by investing activities increased by $119.8 million to $54.0 million for the year ended December 31, 2013 from a use of cash of $65.8 million for the same period in 2012. The increase in cash provided by investing activities is due to a change in restricted cash of $130.4 million due to the changes in our debt service reserve account balances related to the $75.0 million secured debt facility and the $40.0 million secured debt facility and decreased capital expenditures of $68.7 million due to the funding of our share of capital expenditures for Block Z-1 provided by Pacific Rubiales under the carry agreement, partially offset by net proceeds received from our divestiture of a 49% participating interest in Block Z-1 of $79.3 million in 2012.

2014 Capital Expenditures

During the year ended December 31, 2014, we incurred net capital expenditures of approximately $33.1 million associated with the development initiatives for the exploration and production of oil and natural gas reserves and the complementary development of gas-fired power generation of electricity for sale in Peru.

The capital expenditures added were approximately $18.8 million related to the exploration of Block XXIII, which included capitalized interest of $1.6 million, approximately $7.7 million of costs related to the power plant, which consisted of capitalized interest of $7.1 million, and other capital expenditures incurred of approximately $6.6 million (which includes $1.8 million related to Block Z-1), which included capitalized interest of $0.5 million.

The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012. Pacific Rubiales provided funding for capital expenditures for Block Z-1 of $177.9 million for the year ended December 31, 2014. The gross capital expenditures of Block Z-1 include approximately $63.5 million related to the CX-15 development drilling program, approximately $61.0 million related to the development drilling program in Albacora and expenditures related to the Delfin platform of approximately $18.4 million, the Piedra Redonda platform of approximately $14.8 million and the CX-15 platform of approximately $2.8 million.

For the year ended December 31, 2014, we capitalized no depreciation expense and $9.2 million of interest expense to construction in progress.

2013 Capital Expenditures

During the year ended December 31, 2013, we incurred net capital expenditures of approximately $13.5 million associated with our development initiatives for the exploration and production of oil and natural gas reserves and the complementary development of gas-fired power generation of electricity for sale in Peru.

During the year ended December 31, 2013, we incurred capital expenditures of approximately $8.8 million of costs related to the power plant, which consisted of capitalized interest of $8.0 million, approximately $2.4 million related to the Block XXIII exploratory drilling program, and capital expenditures incurred related to marine, information technology and other projects of $2.3 million, which included capitalized interest of $1.9 million.

The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012. Pursuant to the carry agreement, Pacific Rubiales provided funding for 100% of capital expenditures for Block Z-1 of $80.6 million for the year ended December 31, 2013. These gross capital expenditures included approximately $38.6 million related to the CX-15 development drilling program, $17.9 million related to the development drilling program at Albacora, the costs incurred in the design, fabrication, installation and pipeline connections related to the CX-15 platform of approximately $14.1 million and $4.2 million associated with the Corvina offshore Lease Automatic Custody Transfer unit.

For the year ended December 31, 2013, we capitalized no depreciation expense and $9.9 million of interest expense to construction in progress.

2014 Financing Activities

Cash used in financing activities decreased by $27.3 million to a use of cash of $0.2 for the year ended December 31, 2014, compared to a use of cash of $27.5 million for the same period in 2013. The decrease in cash used in financing activities is due to debt repayments of $99.1 million in 2013 compared to zero in 2014 (the repayment of $38.8 million under the $75.0 million secured facility in 2013, the repayment of $49.3 million under the $40.0 million secured facility in 2013 and the repayment of $11.0 million under the 2015 Convertible Notes in 2013) and debt issue costs and other of $6.8 million in 2013 compared to $0.3 million in 2014, partially offset by debt borrowings in 2013 of $78.4 million compared to zero in 2014 (drawdown of $14.5 million from the $40.0 secured debt facility in May 2013 and the issuance of the 2017 Convertible Notes of $63.9 million in September 2013).

2013 Financing Activities

Cash used in financing activities decreased by $164.8 million to a use of cash of $27.5 million for the year ended December 31, 2013, compared to a source of cash of $137.3 million for the same period in 2012. The increase in cash used in financing activities is due to lower borrowings of $117.3 million in 2013 compared to 2012 (borrowing of $195.7 million from Pacific Rubiales in 2012 as compared to the drawdown of $14.5 million from the $40.0 million secured debt facility in May 2013 and the issuance of the 2017 Convertible Notes of $63.9 million), higher repayments of $44.2 million in 2013 compared to 2012 (the repayment of $38.8 million under the $75.0 million secured facility, the repayment of $49.3 million under the $40.0 million secured facility and the repayment of $11.0 million under the 2015 Convertible Notes in 2013 as compared to the repayments of $43.7 million under the $75.0 million secured facility, $7.9 million under the $40.0 million secured debt facility and $3.3 million for capital leases in 2012) and higher debt issue costs and other of $3.3 million in 2013 compared to 2012.

Lima Stock Exchange Listing

In October 2011, we were approved for listing on the Bolsa de Valores in Lima, Peru (BVL). Our common shares trade in United States dollar currency on the Lima stock exchange under the symbol "BPZ".

Debt Obligations

At December 31, 2014 and 2013, debt obligations consist of the following:

	December 31, 2014	December 31, 2013
	(in thousands)	
Convertible Notes, 8.5%, due October 2017, net of discount of ($13.9) million at December 31, 2014 and ($18.3) million at December 31, 2013	$ 154,839	$ 125,416
Convertible Notes, 6.5%, due March 2015, net of discount of ($0.4) million at December 31, 2014 and ($4.4) million at December 31, 2013	59,473	81,523
	214,312	206,939
Less: Current maturity of long-term debt	214,312	-
Long-term debt, net	$ -	$ 206,939

As a result of our decision to not pay the principal and interest on the 2015 Convertible Notes when due on March 1, 2015 and after exercise of a grace period until March 10, 2015, a cross default provision contained on the 2017 Convertible Notes was triggered. In addition, we voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code on March 9, 2015, which was also an event of default under both the 2015 Convertible Notes and the 2017 Convertible Notes. Therefore all of our debt and related interest is considered due and callable once the default provisions were triggered and, all debt has been classified as current at December 31, 2014. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

Convertible Notes due 2017

During the third quarter of 2013, we closed on an offering for an aggregate principal amount of $143.8 million of convertible notes due 2017 which includes the exercise of the underwriter's option to purchase an additional $18.8 million of the 2017 Convertible Notes in addition to the original offering of $125.0 million. The 2017 Convertible Notes are general senior unsecured obligations and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in the right of payment to all of our existing and future subordinated debt. The 2017 Convertible Notes are subordinate to any secured indebtedness we may have to the extent of the value of the assets collateralizing such indebtedness. The 2017 Convertible Notes are not guaranteed by our subsidiaries. In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result, we had $168.7 million principal amount of 2017 Convertible Notes outstanding at December 31, 2014.

The interest rate on the 2017 Convertible Notes is 8.50% per year with interest payments due on April 1st and October 1st of each year. The 2017 Convertible Notes mature with repayment of the $168.7 million principal amount (assuming no conversion) on October 1, 2017 (the "2017 Maturity Date").

The conversion rate is 249.5866 shares per $1,000 principal amount (equal to an initial conversion price of approximately $4.0066 per share of common stock). Upon conversion, if conversion is elected by the noteholders, we must deliver, at our option, either (1) a number of shares of our common stock determined as set forth in the Indenture dated September 24, 2013 (the “2013 Indenture”), (2) cash, or (3) a combination of cash and shares of our common stock.

Holders may convert their 2017 Convertible Notes at their option at any time prior to the close of business on the second business day immediately preceding the 2017 Maturity Date under any of the following circumstances:

(1) during any fiscal quarter (and only during such fiscal quarter) commencing after October 1, 2013, if the last reported sale price of our common stock is greater than or equal to 130% of the conversion price of the 2017 Convertible Notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter;

(2) prior to July 1, 2017, during the five business-day period after any ten consecutive trading-day period in which the trading price of $1,000 principal amount of the 2017 Convertible Notes for each trading day in the measurement period was less than 97% of the product of the last reported sale price of our common stock and the conversion rate on such trading day; or

(3) upon the occurrence of one of a specified number of corporate transactions.

Holders may also convert the 2017 Convertible Notes at their option at any time beginning on July 1, 2017, and ending at the close of business on the second business day immediately preceding the 2017 Maturity Date or may hold the 2017 Convertible Notes to maturity and be paid their outstanding principal in cash.

We may not redeem the 2017 Convertible Notes prior to the 2017 Maturity Date.

The 2013 Indenture for the 2017 Convertible Notes contains customary terms and covenants and events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the 2017 Convertible Notes including (i) an event of default if the Company defaults in the payment when due, after the expiration of any applicable grace period, of indebtedness for money borrowed (including the 2015 Convertible Notes) in the aggregate principal amount then outstanding of $25 million or more, permitting the trustee or the holder of at least 25% in the aggregate principal amount of the outstanding 2017 Convertible Notes to declare the full amount of the principal and interest due thereunder immediately due and payable, and (ii) an event of default if the Company commences a voluntary case under any bankruptcy law, insolvency law or other similar law, whereby the full amount of the principal and interest due thereunder automatically and immediately becomes due and payable. See “—Convertible Notes due 2015” below.

Net proceeds from the sale of the 2017 Convertible Notes, after deducting the discounts and commissions and any offering expenses payable by us, were approximately $124.5 million. The 2017 Convertible Notes were issued with a 10% discount or $14.4 million. The underwriter received commissions of approximately $4.3 million in connection with the sale and we incurred $0.6 million of direct expenses in connection with the offering. We used the net proceeds for general corporate purposes, including funding of our exploration and production efforts, other projects and to reduce or refinance our outstanding debt.

We account for the 2017 Convertible Notes in accordance with ASC Topic 470, “Debt”, as it pertains to accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). Under the accounting guidance, convertible debt instruments that may be settled entirely or partially in cash upon conversion are required to be separated into liability and equity components, with the liability component amount determined in a manner that reflects the issuer’s non-convertible debt borrowing rate. The value assigned to the liability component is determined by measuring the fair value of a similar liability that does not have an equity conversion feature. The value assigned to the equity component is determined by deducting the fair value of the liability component from the initial proceeds. The excess of the principal amount of the liability component over its carrying amount (the non-cash discount) is amortized to interest cost using the effective interest method over the term of the 2017 Convertible Notes. In addition, transaction costs incurred that directly relate to the issuance of convertible debt instruments must be allocated to the liability and equity components in proportion to the allocation of proceeds and accounted for as debt issuance costs and equity issuance costs, respectively.

We estimated our non-convertible borrowing rate at the date of issuance of the 2017 Convertible Notes to be 12.9%. The 12.9% non-convertible borrowing rate represented the borrowing rate of similar companies with the same credit quality as us and was obtained through a quote from the underwriter. Using the income method and discounting the principal and interest payments of the 2017 Convertible Notes using the 12.9% non-convertible borrowing rate, we estimated the fair value of the $143.8 million 2017 Convertible Notes to be approximately $124.5 million, with the discount being approximately $19.3 million. The discount of $19.3 million includes the 10% discount of $14.4 million and the value of the equity component of $4.9 million. The discount is being amortized as non-cash interest expense over the life of the 2017 Convertible Notes using the effective interest method. In addition, we allocated approximately $2.3 million of the $4.9 million of fees and commissions as debt issue costs that are being amortized as non-cash interest expense over the life of the notes using the effective interest method. Approximately $0.1 million of fees and commissions were treated as transaction costs associated with the equity component and the remaining $2.5 million was expensed to other expense under the caption “Other income (expense)” in the third quarter of 2013.

As a result of the exchange during the second quarter of 2014, we estimated our non-convertible borrowing rate at the date of issuance of the $25.0 million 2017 Convertible Notes to be 7.89%. The 7.89% non-convertible borrowing rate represented the borrowing rate of similar companies with the same credit quality as us and was obtained through a quote from a financial advisor. Using the income method and discounting the principal and interest payments of the 2017 Convertible Notes with the 7.89% non-convertible borrowing rate, we estimated the fair value of the $25.0 million 2017 Convertible Notes to be approximately $25.4 million, with the premium being approximately $0.4 million. The value of the equity component was estimated at $0.5 million. The premium is being amortized as non-cash interest expense over the life of the 2017 Convertible Notes using the effective interest method. In addition, approximately $0.3 million of fees were considered debt issue costs that are being amortized as a non-cash interest expense over the life of the notes using the effective interest method. We recognized a loss on this transaction of approximately $0.9 million and this loss was included in the “Loss on extinguishment of debt” in the consolidated statement of operations in the second quarter of 2014. For further information on debt issue costs see Note-7, “Prepaid and Other Current Assets and Other Non-Current Assets.”

As a result of our decision to not pay the principal and interest on the 2015 Convertible Notes when due on March 1, 2015 and after exercise of a grace period until March 10, 2015, a cross default provision contained on the 2017 Convertible Notes was triggered. In addition, we voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code on March 9, 2015, which was an event of default under both the 2015 Convertible Notes and the 2017 Convertible Notes. Therefore all of our debt and related interest is considered due and callable once the default provisions were triggered and all debt has been classified as current at December 31, 2014. The following table shows the estimated remaining cash payments including interest payments related to the 2017 Convertible Notes, assuming no conversion (in thousands):

Year		
2015	$	175,880
2016		-
2017		-
Total estimated remaining cash payments related to the 2017 Convertible Notes	$	175,880

We evaluated the 2013 Indenture for the 2017 Convertible Notes for potential embedded derivatives, noting that the conversion feature and make-whole provisions did not meet the embedded derivative criteria as set forth in ASC Topic 815, “Derivatives and Hedging”. Therefore, no additional amounts have been recorded for those items.

As of December 31, 2014, the net amount of $154.8 million includes the $168.7 million of principal reduced by $13.9 million of the remaining unamortized discount. The remaining unamortized discount of $13.9 million may be written off as a result of the Chapter 11 Case. However, if the structure of the debt remains unchanged after the post Chapter 11 proceeding the unamortized discount will be amortized into interest expense, using the effective interest method, over the remaining life of the 2017 Convertible Notes, which mature in October 2017. We are currently in default on our 2017 Convertible

Notes. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described this Item 7 under the caption "—Voluntary Reorganization Under Chapter 11" and "Item 3. Legal Proceedings—Legal Proceedings Related to the Chapter 11 Case." At December 31, 2014, using the conversion rate of 249.5866 shares per $1,000 principal amount of the 2017 Convertible Notes, if the $168.7 million of principal were converted into shares of common stock, the notes would convert into approximately 42.1 million shares of common stock. As of December 31, 2014, there is no excess if-converted value to the holders of the 2017 Convertible Notes as the price of our common stock at December 31, 2014, $0.29 per share, is less than the conversion price.

The annual effective interest rate on the 2017 Convertible Notes, including the amortization of debt issue costs, is approximately 12.5%.

The following table shows the amount of interest expense related to the 2017 Convertible Notes, disregarding capitalized interest considerations, for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Interest expense related to the contractual interest coupon	$ 13,755	$ 3,258	$ -
Amortization of debt discount expense	4,005	959	-
Amortization of debt issue costs	610	135	-
Interest expense related to the 2017 Convertible Notes	$ 18,370	$ 4,352	$ -

Convertible Notes due 2015

During the first quarter of 2010, we closed on a private offering for an aggregate principal amount of $170.9 million of convertible notes due 2015. The 2015 Convertible Notes are our general senior unsecured obligations and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness. The 2015 Convertible Notes are subordinate to all of our secured indebtedness to the extent of the value of the assets collateralizing such indebtedness. The 2015 Convertible Notes are not guaranteed by our subsidiaries. In September 2013, we repurchased $85.0 million of the principal balance of the $170.9 million of the 2015 Convertible Notes, leaving a principal balance of $85.9 million. In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result, we had $59.9 million principal amount of 2015 Convertible Notes outstanding at December 31, 2014.

The interest rate on the 2015 Convertible Notes is 6.50% per year with interest payments due on March 1st and September 1st of each year. The 2015 Convertible Notes mature with repayment of the $59.9 million principal amount (assuming no conversion) on March 1, 2015 (the "2015 Maturity Date").

We elected not to pay the approximately $62 million in principal and interest due on March 1, 2015 on the 2015 Convertible Notes in order to use a 10-day grace period on principal due and a 30-day grace period on interest due to continue discussions with our debt holders regarding potential terms under which either one or both of the 2015 Convertible Notes and 2017 Convertible Notes could be restructured to provide a capital structure which would allow us to continue developing our oil and gas assets, and discussions with potential investors regarding alternative financing solutions. We were unable to reach an appropriate solution during the grace period and are in default on payment of the principal amount due under our 2015 Convertible Notes due on March 10, 2015 following our exercise of a 10-day grace period, which also triggered an event of default under our 2017 Convertible Notes, allowing the trustee or the holders of at least 25% in aggregate principal amount under each set of notes to declare the full amounts of principal and interest due. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described in this Item under the caption "—Voluntary Reorganization Under Chapter 11." The filing of the Chapter 11 Case also constituted an event of default that triggered repayment obligations under the 2015 Convertible Notes and the 2017 Convertible Notes. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 Case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

The initial conversion rate of 148.3856 shares per $1,000 principal amount (equal to an initial conversion price of approximately $6.74 per share of common stock) was adjusted on February 3, 2011 in accordance with the terms of the Indenture agreement dated February 8, 2010 (the "2010 Indenture").

As a result, the conversion rate and conversion price changed to 169.0082 shares per $1,000 principal amount and $5.9169 per share of common stock, respectively. Upon conversion, if conversion is elected by the noteholders, we must deliver, at our option, either (1) a number of shares of our common stock determined as set forth in the 2010 Indenture, (2) cash, or (3) a combination of cash and shares of our common stock.

Holders were permitted to convert their 2015 Convertible Notes at their option at any time prior to the close of business on the second business day immediately preceding the 2015 Maturity Date under any of the following circumstances:

(1) during any fiscal quarter (and only during such fiscal quarter) commencing after March 31, 2010, if the last reported sale price of our common stock is greater than or equal to 130% of the conversion price of the 2015 Convertible Notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter;

(2) prior to January 1, 2015, during the five business-day period after any ten consecutive trading-day period in which the trading price of $1,000 principal amount of the 2015 Convertible Notes for each trading day in the measurement period was less than 97% of the product of the last reported sale price of our common stock and the conversion rate on such trading day;

(3) if the 2015 Convertible Notes have been called for redemption; or

(4) upon the occurrence of one of a specified number of corporate transactions.

Holders were also permitted to convert the 2015 Convertible Notes at their option at any time beginning on February 1, 2015, and ending at the close of business on the second business day immediately preceding the 2015 Maturity Date or may hold the 2015 Convertible Notes to maturity and be paid their outstanding principal in cash.

As of February 3, 2013, we were permitted to redeem for cash all or a portion of the 2015 Convertible Notes at a redemption price of 100% of the principal amount of the notes to be redeemed plus any accrued and unpaid interest to, but not including, the redemption date, plus a "make-whole" payment if: (1) for at least 20 trading days in any consecutive 30 trading days ending within 5 trading days immediately before the date we mail the redemption notice, the "last reported sale price" of its common stock exceeded 175% of the conversion price in effect on that trading day, and (2) there is no continuing default with respect to the notes that has not been cured or waived on or before the redemption date.

No holders converted their 2015 Convertible Notes and we did not redeem any 2015 Convertible Notes prior to the 2015 Maturity Date.

The 2010 Indenture for the 2015 Convertible Notes contains customary terms and covenants and events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the 2015 Convertible Notes.

Net proceeds from the sale of the $170.9 million of 2015 Convertible Notes, after deducting the discounts and commissions and any offering expenses payable by us, were approximately $164.9 million. The initial purchaser received commissions of approximately $5.5 million in connection with the sale and we incurred approximately $0.6 million of direct expenses in connection with the offering. We used the net proceeds for general corporate purposes, including capital expenditures and working capital, reduction or refinancing of debt, and other corporate obligations.

We account for the 2015 Convertible Notes in accordance with ASC Topic 470, "Debt," as it pertains to accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). Under the accounting guidance, convertible debt instruments that may be settled entirely or partially in cash upon conversion are required to be separated into liability and equity components, with the liability component amount determined in a manner that reflects the issuer's non-convertible debt borrowing rate. The value assigned to the liability component is determined by measuring the fair value of a similar liability that does not have an equity conversion feature. The value assigned to the equity component is determined by deducting the fair value of the liability component from the initial proceeds. The excess of the principal amount of the liability component over its carrying amount (the non-cash discount) is amortized to interest cost using the effective interest method over the term of the 2015 Convertible Notes. In addition, transaction costs incurred that directly relate to the issuance of convertible debt instruments must be allocated to the liability and equity components in proportion to the allocation of proceeds and accounted for as debt issuance costs and equity issuance costs, respectively.

We estimated our non-convertible borrowing rate at the date of issuance of the 2015 Convertible Notes to be 12%. The 12% non-convertible borrowing rate represented the borrowing rate of similar companies with the same credit quality as us and was obtained through a quote from the initial purchaser. Using the income method and discounting the principal and interest payments of the 2015 Convertible Notes using the 12% non-convertible borrowing rate, we estimated the fair value of the $170.9 million 2015 Convertible Notes to be approximately $136.3 million with the discount being approximately $34.6 million. The discount is being amortized as non-cash interest expense over the life of the notes using the effective interest method. In addition, we allocated approximately $4.8 million of the $6.1 million of fees and commissions as debt issue costs that are being amortized as non-cash interest expense over the life of the 2015 Convertible Notes using the effective interest method. The remaining $1.3 million of fees and commissions were treated as transaction costs associated with the equity component. The net amount of the equity component was $33.3 million, which included the initial discount of $34.6 million reduced by $1.3 million of direct transaction costs.

In September 2013, we repurchased $85.0 million of aggregate principal amount of the 2015 Convertible Notes. As a result of the $85.0 million repurchase during the third quarter of 2013, approximately $12.2 million of the repayment was considered a retirement of debt and the remaining $72.8 million of the repayment was considered an exchange of debt. The $85.0 million of 2015 Convertible Notes were repurchased with an approximate discount of 10%. We recognized a gain on the retirement of the debt of approximately $0.2 million and this gain was included in the "Loss on extinguishment of debt" in the consolidated statement of operations in the third quarter of 2013. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

As a result of the exchange during the second quarter of 2014, the $26.0 million of aggregate principal amount of 2015 Convertible Notes exchanged was considered a retirement of debt and deemed a substantial modification of debt. The $26.0 million of 2015 Convertible Notes were exchanged with an approximate discount of 4%. We recognized a loss on the retirement of the debt of approximately $0.3 million and this loss was included in the "Loss on extinguishment of debt" in the consolidated statement of operations in the second quarter of 2014. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

The following table shows the estimated remaining cash payments including interest payments related to the 2015 Convertible Notes, assuming no conversion (in thousands):

Year		
2015	$	61,837
Total estimated remaining cash payments related to the 2015 Convertible Notes	$	61,837

We evaluated the 2010 Indenture for the 2015 Convertible Notes for potential embedded derivatives, noting that the conversion feature and make-whole provisions did not meet the embedded derivative criteria as set forth in ASC Topic 815, "Derivatives and Hedging." Therefore, no additional amounts have been recorded for those items.

As of December 31, 2014, the net amount of $59.5 million of 2015 Convertible Notes outstanding includes the $59.9 million of principal reduced by $0.4 million of the remaining unamortized discount. The remaining unamortized discount of $0.4 million may be written off as a result of the Chapter 11 Case. However, if the structure of the debt remains unchanged after the post-Chapter 11 Case proceeding the unamortized discount will be amortized into interest expense, using the effective interest method, over the remaining life of the 2015 Convertible Notes, which mature in March 2015. We are currently in default on our 2015 Convertible Notes. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described in Item 7 under the caption "—Voluntary Reorganization Under Chapter 11" and "Item 3. Legal Proceedings—Legal Proceedings Related to the Chapter 11 Case." At December 31, 2014, using the conversion rate of 169.0082 shares per $1,000 principal amount of the 2015 Convertible Notes, if the $59.9 million of principal were converted into shares of common stock, the notes would convert into approximately 10.1 million shares of common stock. As of December 31, 2014, there is no excess if-converted value to the holders of the 2015 Convertible Notes as the price of our common stock at December 31, 2014, $0.29 per share, is less than the conversion price.

For the year ended December 31, 2014, the annual effective interest rate on the 2015 Convertible Notes, including the amortization of debt issue costs, was approximately 12.0%.

The following table shows the amount of interest expense related to the 2015 Convertible Notes, disregarding capitalized interest considerations, for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Interest expense related to the contractual interest coupon	$ 4,386	$ 9,622	$ 11,111
Amortization of debt discount expense	2,896	6,051	6,698
Amortization of debt issue costs	762	977	956
Interest expense related to the 2015 Convertible Notes	$ 8,044	$ 16,650	$ 18,765

$75.0 Million Secured Debt Facility

On July 6, 2011, we and our subsidiaries entered into a credit agreement with the lenders, whereby the lenders agreed to provide a $75.0 million secured debt facility in two loan tranches to our subsidiary, BPZ E&P. The full amount available under the $75.0 million secured debt facility was drawn down by us on July 7, 2011. In April 2012, we and the lenders amended the terms of the $75.0 million secured debt facility and in May 2012, we prepaid $40.0 million of the principal balance of the $75.0 million secured debt facility. In May 2013, we prepaid the remaining principal balance of the $75.0 million secured debt facility.

Proceeds from the $75.0 million secured debt facility were utilized to pay certain fees and expenses under the $75.0 million secured debt facility, to fund a debt service reserve account under the $75.0 million secured debt facility, to reimburse certain affiliates of BPZ E&P for up to $14.0 million of capital and exploratory expenditures incurred by them in connection with the development of Block Z-1 and up to $6.0 million of capital and exploratory expenditures incurred by them in connection with the development in Block XIX in northwest Peru, and to finance BPZ E&P's capital and exploratory expenditures in connection with the development of Block Z-1.

As a result of the prepayment of the remaining principal balance during the second quarter of 2013, we incurred $2.4 million of fees and a prepayment premium. The $2.4 million in fees and prepayment premium were recognized as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations in the second quarter of 2013. Approximately $1.4 million representing the remaining unamortized debt issue costs on the loan was expensed as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations when we prepaid the remaining principal in the second quarter of 2013. For further information on debt issue costs, see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

As a result of the prepayment and amendment during the second quarter of 2012, we incurred $5.8 million of fees and prepayment premium and $1.1 million of debt issue costs. The $5.8 million in fees and prepayment premium were recognized as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations, of which 25% was paid at the time of the amendment and prepayment and 25% was paid at the time of each of the next three quarterly interest payment dates ending in January 2013. Approximately $1.5 million of the remaining $2.8 million of unamortized debt issue costs associated with the initial loan was expensed as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations when we prepaid $40.0 million of principal. For further information on debt issue costs, see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

The $75.0 million secured debt facility, as amended, provided for an ongoing fee through July 2014 payable by BPZ E&P to the lenders, of the Performance Based Arranger Fee whose amount is determined by the change in the price of Brent crude oil at inception of the loans and the price at each principal repayment date in accordance with the original loan principal repayment dates, subject to a 12% ceiling of the original principal amount borrowed. For further information on the Performance Based Arranger Fee, see Note-13, "Derivative Financial Instruments" and Note-15, "Fair Value Measurements and Disclosures."

$40.0 Million Secured Debt Facility

In January 2011, we, through our subsidiaries, completed a credit agreement with Credit Suisse whereby Credit Suisse provided a $40.0 million secured debt facility to our power generation subsidiary, Empresa Eléctrica Nueva Esperanza S.R.L. On April 27, 2012, we and our subsidiaries, Empresa Eléctrica Nueva Esperanza S.R.L. and BPZ E&P, entered into a fourth amendment to the $40.0 million secured debt facility with Credit Suisse. In May 2013, we amended and restated the $40.0 million secured debt facility (which had been repaid by scheduled principal repayments to $25.5 million) by increasing the facility size and borrowing an additional $14.5 million. In September 2013, we prepaid the remaining principal balance of the $40.0 million secured debt facility.

In 2013, the $14.5 million of proceeds from the amended and restated $40.0 million secured debt facility was utilized to meet our 2013 capital, exploration and development work programs as well, as for general corporate purposes. In 2011, the proceeds from the $40.0 million secured debt facility were utilized to meet our 2011 capital, exploration and development work programs, and to reduce other debt obligations.

As a result of the prepayment of the remaining principal balance during the third quarter of 2013, we incurred $2.0 million in fees and prepayment premium. The $2.0 million in fees and prepayment premium were recognized as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations. Approximately $1.7 million representing the remaining unamortized debt issue costs loan was expensed as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations when we prepaid the remaining principal. For information on debt issue costs, see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

In May 2013, as a result of amending and restating the $40.0 million secured debt facility (which had been repaid by scheduled principal repayments to $25.5 million) to increase the facility size and borrowing an additional $14.5 million, we added $1.8 million of debt issue costs. The $1.8 million of new debt issue costs was combined with the remaining $0.6 million of unamortized debt issue costs and was originally planned to be amortized over the remaining term, ending in January 2015, using the effective interest method. For further information on debt issue costs, see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

The $40.0 million secured debt facility, as amended, provided for ongoing fees through July 2013 payable to Credit Suisse including a Performance Based Arranger Fee whose amount is determined by the change in the price of Brent crude oil at inception of the loan and the price at each principal repayment date in accordance with the original loan principal repayment dates, subject to a 18% ceiling of the original principal amount borrowed. For further information on the Performance Based Arranger Fee, see Note-13, "Derivative Financial Instruments" and Note-15, "Fair Value Measurements and Disclosures."

Pacific Rubiales Obligations

On April 27, 2012, we and Pacific Rubiales executed a SPA where we formed an unincorporated joint venture with Pacific Rubiales to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the SPA, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of our share of capital and exploratory expenditures in Block Z-1 from the effective date of the SPA, January 1, 2012 (together, the "Pacific Rubiales Loans"). Until the required approvals were obtained, Pacific Rubiales provided us $65.0 million and other funds as loans to continue to fund our Block Z-1 capital and exploratory activities. These amounts were reflected as long-term debt prior to closing the transaction.

On December 14, 2012, Perupetro approved the terms of the amendment to the Block Z-1 License Contract to recognize the sale of a 49% participating interest in offshore Block Z-1 to Pacific Rubiales. We and Pacific Rubiales waived and modified certain contract conditions in order to close the transaction. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

At closing, Pacific Rubiales exchanged certain loans along with an additional $85.0 million, plus any other amounts due to us or from us under the SPA, for the interests and assets obtained from us under the SPA and under the Block Z-1 License Contract.

At December 31, 2014 and December 31, 2013, we reflected $22.5 million and $23.9 million, respectively, as other current liabilities and zero and $16.8 million, respectively, as other non-current liabilities for exploratory expenditures related to Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount is being settled by us and Pacific Rubiales under the terms of the SPA, with cash payments under the liability of $14.4 million made in 2014.

Capital Leases

In June 2007, we entered into a capital lease agreement, with an option to purchase, for two vessels, the Namoku and the Nu'uanu, to assist in the development of the Corvina oil field. The capital lease assets were recorded at $6.2 million, which represented the present value of the minimum lease payments, or the aggregate fair market value of the assets.

In May 2009, we entered into an amendment of our lease agreement for two vessels under charter, the Namoku and the Nu'uanu. Under the terms of the amended lease agreement, the charter, originally set to expire in November 2009, was extended for five years commencing on May 1, 2009. During the first 18 months of the amended lease term, the daily charter rate for the use of both vessels was fixed. Commencing in November 2010, the daily charter rate for the use of both vessels was based on a tiered structure with the daily rate dependent upon the amount of the previous month's average daily per barrel price of West Texas Intermediate Crude Oil ("WTI"), as indicated on the New York Mercantile Exchange. Any amount paid by us after November 2010 over the initial daily rate as a result of the escalated tiered structure based on the price of WTI was considered contingent rental payments. The amount of the contingent lease payments paid in 2012 was $0.6 million. The amended lease agreement contained a $3.0 million purchase option after the third year of the lease, a $2.0 million purchase option after the fourth year of the lease and a mandatory $1.0 million purchase obligation by us after the fifth year of the lease. We accounted for the amended lease agreement in accordance with ASC Topic 840, "Leases." Under the guidance, the lease agreement continued to be accounted for as a capital lease and the imputed interest rate necessary to reduce the net minimum lease payments to present value over the lease term is 34.9%. In May 2012, we exercised the third year purchase option for $3.0 million and purchased the marine vessels, Namoku and the Nu'uanu, at which point titles to the vessels were transferred to us.

At December 31, 2014 and December 31, 2013, we had no amounts outstanding under capital leases.

Interest Expense

The following table is a summary of interest expense for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Interest expense	$ 27,920	$ 26,016	$ 31,719
Capitalized interest expense	(9,250)	(9,858)	(15,604)
Interest expense, net	$ 18,670	$ 16,158	$ 16,115

Restricted Cash and Performance Bonds

Below is a summary of restricted cash as of December 31, 2014 and December 31, 2013:

	December 31, 2014	December 31, 2013
	(in thousands)	
Performance bonds totaling $5.7 million for properties in Peru	$ 1,559	$ 3,459
Performance obligations and commitments for the gas-to-power site	650	650
Secured letters of credit	-	250
$40.0 million secured debt facility	-	1,000
Unsecured performance bond totaling $0.1 million for office lease agreement	-	-
Restricted cash	$ 2,209	$ 5,359
Current portion of restricted cash as of the end of the period	$ -	$ 1,250
Long-term portion of restricted cash as of the end of the period	$ 2,209	$ 4,109

The $75.0 million secured debt facility we entered into in July 2011 required us to establish a $2.5 million debt service reserve account during the first 15 months the debt facility was outstanding. After the first 15-month period, we were required to keep a balance in the debt service reserve account equal to the aggregate amount of principal and interest due on the next quarterly repayment date. The requirement was subsequently amended subject to the closing of the sale of a 49% participating interest in Block Z-1 to require the funding of the debt service reserve account related to the $75.0 million secured debt facility in the amount of outstanding principal. The remaining principal balance related to the $75.0 million secured debt facility was repaid in May 2013 utilizing the funds in the debt service reserve account related to this debt facility, bringing both the current and non-current balances to zero at December 31, 2013.

The $40.0 million secured debt facility we entered into in January 2011 required us to establish a $2.0 million debt service reserve account during the first 18-month period and, thereafter, to maintain a balance in the debt service reserve account equal to the aggregate amount of principal and interest payment on the $40.0 million secured debt facility due on the succeeding principal repayment date. The requirement was amended subject to the closing of the sale of a 49% participating interest in Block Z-1 to increase the funding of the debt service reserve account related to the $40.0 million secured debt facility to the amount of outstanding principal. The requirement was subsequently changed when we amended and restated the $40.0 million secured debt facility in May 2013 for us to maintain a balance in the debt service reserve account equal to the aggregate amount of principal and interest payment on the $40.0 million secured debt facility due on the succeeding principal repayment date. The remaining principal balance related to the $40.0 million secured debt facility was repaid in September 2013 utilizing $3.8 million of funds from the debt service reserve account related to this debt facility. As a result of the repayment of the remaining principal balance of the $40.0 million secured debt facility, it was agreed that the restricted cash balance would remain at $1.0 million relating to the Performance Based Arranger Fee for the $75.0 million secured debt facility through July 2014. In July 2014 the $1.0 million was released to the Company and the debt service reserve account was terminated. Therefore, the restricted cash balance related to the current and non-current portion of the $40.0 million secured debt financing were both zero at December 31, 2014. The restricted cash balance related to the current and non-current portion of the $40.0 million secured debt financing was $1.0 million and none, respectively, at December 31, 2013.

All of the performance and insurance bonds are issued by Peruvian banks and their terms are governed by the corresponding license contracts, customs laws, legal requirements or rental practices.

2015 Estimated Capital and Exploratory Expenditures Budget

Our current plans contemplate spending approximately $58.6 million in 2015 on capital and exploratory expenditures, excluding capitalized interest, for our share of capital and exploratory expenditures for offshore Block Z-1 and our three onshore blocks in which we hold 100% working interests.

Our 51% share of the Block Z-1 capital investments is budgeted at $52.5 million ($102.9 million gross). Our planned activities at Block Z-1 include $15.0 million of CX-15 developmental drilling for 3 wells, $8.0 million of Albacora developmental drilling for 1 well and $29.5 million for projects and engineering and other expenditures, which includes $6.8 million ($13.3 million gross) related to the Defin and Piedra Redonda platforms, which will be completed, but the installation deferred until a future date.

Our $6.1 million planned capital and exploratory expenditures onshore include $1.9 million for testing activities at Block XXIII as well as $4.2 million of other geological, geophysical and engineering activities.

Liquidity Outlook

The matters described herein, to the extent that they relate to future events or expectations, may be significantly affected by the Chapter 11 Case. As a result of the risks and uncertainties associated with the Chapter 11 Case, the value of our liabilities and securities is highly speculative and trading in the Company's securities during the pendency of the Chapter 11 Case will pose substantial risks. We urge that extreme caution be exercised with respect to existing and future investments in any of the liabilities and/or securities of the Debtor. See "—Voluntary Reorganization Under Chapter 11" under this Item 7 and Item 1A." Risk Factors—Risks Related to Bankruptcy" regarding the impact of the Chapter 11 Case and the proceedings in Bankruptcy Court on the Debtor, the Debtor's liquidity and its status as a going concern and its stakeholders.

Our major sources of funding to date have been oil sales, equity and debt financing activities when market conditions permit and asset sales. The recent severe downturn in global economic conditions for oil and gas companies has impaired our near-term possibilities to strengthen the balance sheet opportunistically and improve cash flows through potential refinancing and debt and equity capital infusions. Further, such conditions have made the sale of certain operating assets and non-strategic assets to generate enhanced liquidity difficult to complete on acceptable terms or at all.

We are in default on payment of the principal amount due under our 2015 Convertible Notes due on March 10, 2015 following our exercise of a 10-day grace period, which also triggered an event of default under our 2017 Convertible Notes, allowing the trustee or the holders of at least 25% in aggregate principal amount of each to declare the full amounts of principal and interest due. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described in Item 7 under the caption "—Voluntary Reorganization Under Chapter 11" and "Item 3. Legal Proceedings—Legal Proceedings Related to the Chapter 11 Case." The filing of the Chapter 11 Case constituted an event of default that triggered repayment obligations under the 2015 Convertible Notes and the 2017 Convertible Notes. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 Case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

The Bankruptcy Case involves various restrictions on our activities, limitations on financing, the need to obtain Bankruptcy Court and Creditors' Committee approval for various matters and uncertainty as to relationships with vendors, suppliers, customers and others with whom we may conduct or seek to conduct business.

None of the Debtor's direct or indirect subsidiaries or affiliates has filed for reorganization under Chapter 11 and none is expected to file for reorganization or protection from creditors under any insolvency or similar law in the U.S. or elsewhere. The Debtor's operating subsidiaries are expected to continue to operate in the normal course of business. We therefore do not expect the Debtor's filing for Chapter 11 protection to impact our license agreements, and the Debtor's corporate guaranty to Perupetro that provides for joint and several liability to Perupetro with respect to the fulfillment of each minimum work program of the license agreements remains in place in addition to the subsidiary performance bonds that are unaffected.

In addition, we expect the Debtor will need to obtain debtor-in-possession ("DIP") financing during the pendency of the Chapter 11 Case. It is not certain that we can secure DIP Financing and, if we can, at what cost. Any such DIP financing will be senior in priority to all of our other debt and equity.

Notwithstanding the direct positive impact of the Chapter 11 Case on our liquidity, including the stay of payments on debt subject to compromise and continuation of our ability to use cash for our operations under the supervision of the Bankruptcy Court and pursuant to certain court approved motions, we are currently uncertain as to the outcome of our petition for reorganization relief, so at this time, we cannot predict if and when we would emerge as a restructured company. Therefore, substantial doubt exists about our ability to continue as a going concern, and therefore, we may be unable to realize the full value of our assets and discharge our liabilities in the normal course of business. In addition, our auditors have expressed substantial doubt about our ability to continue as a going concern. See the Report of Independent Registered Public Accounting Firm included under Item 8. "Financial Statements and Supplementary Data."

Regardless of the results of our reorganization efforts, our current and future liquidity is greatly dependent upon our operating results, which are driven by overall economic conditions, conditions in the oil and gas industry and oil and gas demand and prices, as well as other factors referenced herein and under "Item 1A. Risk Factors" of this Form 10-K. We expect to continue to have significant capital expenditure commitments and debt service obligations on a long-term basis.

Our reorganization may result in additional limitations on levels of debt and debt transactions. If we are successful in raising additional financing or issuing our securities in exchange for an extension of debt, securities comprising a significant percentage of our fully diluted equity capital may be issued in connection with the completion of such transactions, potentially resulting in very substantial dilution to our current equity holders. See "Item 1A. Risk Factors," for risks and uncertainties that could adversely affect our financial condition or short-term or long-term liquidity.

Depending upon the outcome of our restructuring, from time to time, we may consider the feasibility and timing of transactions that could raise capital for additional liquidity, debt reduction, debt extension, refinancing of existing indebtedness and for additional working capital and growth opportunities. There can be no assurance we will be successful in any of these efforts to consummate timely any such transactions or at all or to obtain any such financing on acceptable terms or at all, especially in consideration of the state of the current economic situation for oil and gas companies. If our plans or assumptions change or prove inaccurate, including those with respect to our debt levels, operations or cash flow from operating activities, if we experience unexpected costs or competitive pressures or if existing cash and any other borrowings prove to be insufficient to meet our obligations, we may need to obtain such financing and/or relief sooner than expected. In such circumstances, there can be no assurance we will be successful in these efforts to obtain new capital at acceptable terms or to exchange or to extend debt. Also there can be no assurance that changes in assumptions or conditions, including those referenced herein and under "Item 1A. Risk Factors," will not adversely affect our financial condition or short-term or long-term liquidity.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under U.S. generally accepted accounting principles. As part of our normal ongoing business operations and consistent with normal industry practice, we enter into agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. Such customary agreements in the oil and gas industry include operating leases and commitments. Please see "Contractual Obligations" in this Item 7 below.

On April 27, 2012, we and Pacific Rubiales executed the SPA under which we formed an unincorporated joint venture with Pacific Rubiales to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the SPA, Pacific Rubiales agreed to fund $185.0 million of our share of capital and exploratory expenditures in Block Z-1 from the effective date of the SPA, January 1, 2012.

On December 14, 2012 Perupetro approved the terms of the amendment to the Block Z-1 License Contract to recognize the sale of a 49% participating interest in offshore Block Z-1 to Pacific Rubiales. We and Pacific Rubiales waived and modified certain contract conditions in order to close the transaction. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

The transaction provided for an adjustment based upon the collection of revenues ($56.1 million) and the payment of expenses ($32.6 million) and income taxes ($5.2 million) attributable to the properties that took place after the effective date of January 1, 2012 and prior to the closing date, which was December 14, 2012. These amounts were settled by adjusting down $18.3 million of the unused portion of the agreed funding of $185.0 million by Pacific Rubiales for our share of capital and exploratory expenditures in Block Z-1.

The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014 and we are now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

At December 31, 2013, the carry amount was $81.3 million.

Contractual Obligations

As a result of our decision to not pay the principal and interest on the 2015 Convertible Notes when due on March 1, 2015 and after exercise of a grace period until March 10, 2015, a cross default provision contained on the 2017 Convertible Notes was triggered. In addition, we voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code on March 9, 2015, which was an event of default under both the 2015 Convertible Notes and the 2017 Convertible Notes. Therefore all of our debt and related interest is considered due and callable once the default provisions were triggered and all debt has been classified as current at December 31, 2014. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

	Payments Due by Period at December 31, 2014				
	Total	**Less Than One Year**	**One to Three Years**	**Three to Five Years**	**More Than Five Years**
Contractual Obligations:			**(in thousands)**		
Operating lease obligation (1)	$ 16,584	$ 1,380	$ 2,144	$ 1,795	$ 11,265
Debt obligation (2)	237,717	237,717	-	-	-
Investee entities' debt obligation (3)	1,126	375	751	-	-
Contractual obligation (4)	4,823	2,951	549	302	1,021
Purchase obligation/current liabilities (5)	22,509	22,509	-	-	-

Total	$	282,759	$	264,932	$	3,444	$	2,097	$	12,286

(1) Includes operating leases for our executive office in Houston, Texas (expires in 2016), our branch offices in Peru (expires in 2016 and 2019) and warehouses in Peru (expires in 2038).

(2) Includes the remaining principal amount along with the accrued interest due, on the $168.7 million convertible notes due 2017. The 2017 Convertible Notes are at a rate of 8.50% per year payable on April 1 and October 1 of each year, beginning on April 1, 2014. The 2017 Convertible Notes mature on October 1, 2017. Using an adjusted conversion rate of 249.5866 shares per $1,000 principal amount of the 2017 Convertible Notes, if the $168.7 million of principal were converted into shares of common stock, the notes would convert into 42.1 million shares of common stock.

Includes the remaining principal amount along with the accrued interest due, on the $59.9 million convertible notes due 2015. The 2015 Convertible Notes are at a rate of 6.50% per year payable on March 1 and September 1 of each year, beginning on September 1, 2010. The 2015 Convertible Notes mature on March 1, 2015. Subsequent to December 31, 2011, using an adjusted conversion rate of 169.0082 shares per $1,000 principal amount of the 2015 Convertible Notes, if the $59.9 million of principal were converted into shares of common stock, the notes would convert into 10.1 million shares of common stock.

(3) In the fourth quarter of 2014, the Consortium incurred a loan for the additional work commitments to increase production in the Santa Elena field. The Consortium loan is to be paid with cash generated from the production of the Santa Elena Field. Our total share of this loan would be $1.0 million (our 10% non-operating net profits interest) which amounts are due quarterly through the fourth quarter of 2017. If the Consortium does not have sufficient cash on hand, we would make a cash contribution to the Consortium for our 10% share of this loan.

(4) Includes the estimated cash payments related to our share of the work commitments for the Santa Elena field due from 2015 through 2028.

(5) Includes current liabilities related to exploratory expenditures for Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount will be settled by the Company and Pacific Rubiales under the terms of the SPA.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based on our consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles (“GAAP” or “U.S. GAAP”). Management uses estimates and assumptions in preparing the consolidated financial statements in accordance with GAAP. Those estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses in the consolidated financial statements, and the disclosure of contingent assets and liabilities. We have identified the following as critical accounting policies directly related to our business and operations, and the understanding of our financial statements.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for our investments in oil and gas properties. Under this method, oil and gas lease acquisition costs and intangible drilling costs associated with exploration efforts that result in the discovery of proved reserves and costs associated with development drilling, whether or not successful, are capitalized when incurred. Certain costs of exploratory wells are capitalized pending determinations that proved reserves have been found. If the determination is dependent upon the results of planned additional wells and required capital expenditures to produce the reserves found, the drilling costs will be capitalized as long as sufficient reserves have been found to justify completion of the exploratory well and additional wells are underway or firmly planned to complete the evaluation of the well. All costs related to unsuccessful exploratory wells are expensed when such wells are determined to be non-productive or at the one year anniversary of completion of the well if proved reserves have not been attributed and capital expenditures as described in the preceding sentence are not required. We assess our capitalized exploratory wells pending evaluation each quarter to determine whether costs should remain capitalized or should be charged to earnings. Other exploration costs, including geological and geophysical costs, are expensed as incurred. We recognize gains or losses on the sale of properties, should they occur, on a field-by-field basis.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluations of oil and gas leasehold acquisition costs requires management's judgment to estimate the fair value of exploratory costs related to drilling activity in a given area.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding oil and gas reserves. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. The initial exploratory wells may be unsuccessful and the associated costs will then be expensed as dry hole costs, and any associated leasehold costs may be impaired.

Oil and Gas Accounting Reserves Determination

The successful efforts method of accounting depends on the estimated reserves we believe are recoverable from our oil and gas reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially going forward as additional data from development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the U.S. as prescribed by the Society of Petroleum Engineers. Reserve estimates are independently evaluated at least annually by our independent qualified reserves engineers, NSAI.

Our Technical Committee of the Board of Directors oversees the review of our oil and gas reserves and related disclosures by our appointed independent reserve engineers. The Technical Committee meets with management periodically to review the reserves process and results, and to confirm that the independent reserve engineers have had access to sufficient information, including the nature and satisfactory resolution of any material differences of opinion between us and the reserve engineers.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves;
- calculating our unit-of-production depletion rates. Proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense; and
- assessing, when necessary, our oil and gas assets for impairment using undiscounted future cash flows based on management's estimates. If impairment is indicated, discounted values will be used to determine the fair value of the assets. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Revenue Recognition

We recognize revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectability is reasonably assured.

We sell our production in the Peruvian domestic market on a contract basis. Revenue is recorded net of royalties when the purchaser takes delivery of the oil. At the end of the period, oil that has been produced but not sold is recorded as inventory at the lower of cost or market. Cost is determined on a weighted average based on production costs.

Impairment of Long-Lived Assets

We periodically evaluate the recoverability of the carrying value of our long-lived assets and identifiable intangibles by monitoring and evaluating changes in circumstances that may indicate that the carrying amount of the asset may not be recoverable. Examples of events or changes in circumstances that indicate the recoverability of the carrying amount of an asset should be assessed include, but are not limited to, (a) a significant decrease in the market value of an asset, (b) a significant change in the extent or manner in which an asset is used or a significant physical change in an asset, (c) a significant adverse change in legal factors or in the business climate that could affect the value of an asset or an adverse action or assessment by a regulator, (d) an accumulation of costs significantly in excess of the amount originally expected to acquire or construct an asset, and/or (e) a current period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with an asset used for the purpose of producing revenue.

We consider historical performance, anticipated future results and anticipated proceeds in the event of a sale of the long-lived assets in our evaluation of potential impairment. Accordingly, when indicators of impairment are present, we evaluate the carrying value of these assets in relation to the operating performance of the business and future discounted and non-discounted cash flows expected to result from the use of these assets. Impairment losses are recognized when the expected undiscounted future cash flows from an asset are less than its carrying value.

Future Dismantlement, Restoration, and Abandonment Costs

The accounting for future development and abandonment costs changed on January 1, 2003, with the issuance of ASC Topic 410, "Asset Retirement and Environmental Liabilities," which requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The accrual is based on estimates of these costs for each of our properties based upon the type of production structure, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these costs is difficult and requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology, the political and regulatory environment and estimates as to the proper discount rate to use and timing of abandonment.

In periods subsequent to initial measurement of the asset retirement obligation liability, we recognize period to period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate. Revisions also result in increases or decreases in the carrying cost of the oil and gas asset. Increases in the asset retirement obligation liability due to the passage of time impact income as accretion expense. The related capitalized cost, including revisions, is charged to expense as depreciation, depletion and amortization. Any negative adjustment in excess of asset retirement cost is reclassified to depreciation, depletion and amortization expense.

Our plan of operations includes the drilling of wells. We will be required to plug and abandon those wells and restore the well sites upon abandonment if they are abandoned prior to the end of the contract period. See Note-11, "Asset Retirement Obligation" to the consolidated financial statements provided herein for further detail.

Principles of Consolidation

Our consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and branch offices. All intercompany balances and transactions have been eliminated.

Our accounting policy regarding partnership or joint venture interests in oil and gas properties is to consolidate such interests on a pro-rata basis in accordance with accepted practice in the oil and gas industry. However, we have not been able to receive timely information to allow us to proportionately consolidate the minority non-operated net profits interest owned by our consolidated subsidiary, SMC Ecuador Inc. See Note-9, "Investment in Ecuador Property" to the consolidated financial statements for further discussion regarding the investment in our Ecuador property. Accordingly, we account for this investment under the cost method. As such, we record our share of cash received or paid attributable to this investment as other income or expense and amortize our investment into income over the remaining term of the license agreement and operating agreement covering the property, which was extended in May 2013 from May 2016 to December 2029. The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012 and the entitlement to crude oil production and sharing of joint operating expenditures from that day forward was allocated to each partner. The sharing of any production or joint operating expenditures prior to that date for 2012 was handled as an adjustment to the carry amount under the SPA. In addition, the carry of capital and exploratory expenditures for Block Z-1 by Pacific Rubiales began December 14, 2012, so expenditures for capital and exploratory activities at Block Z-1 have been 100% for the account of Pacific Rubiales during the period of December 14 through December 31, 2012. The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014 and we are now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

Stock Based Compensation

We account for stock-based compensation at fair value in accordance with the provisions of ASC Topic 718, which establishes accounting for stock-based payment transactions for employee services and goods and services received from non-employee directors. Under the provisions of ASC Topic 718, stock-based compensation cost is measured at the date of grant, based on the calculated fair value of the award, and is recognized as expense in the Consolidated Statements of Operations ratably over the employee's or non-employee director's requisite service period, which is generally the vesting period of the equity grant. The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of our common stock on the grant date. Additionally, stock-based compensation cost is recognized based on awards that are ultimately expected to vest, therefore, the compensation cost recognized on stock-based payment transactions is reduced for estimated forfeitures based on our historical forfeiture rates. Additionally, no stock-based compensation costs were capitalized for the year ended December 31, 2014, 2013 and 2012. We provide compensation benefits to employees and non-employee directors under share-based payment arrangements, including various employee stock option plans. ASC Topic 230, "Statement of Cash Flows," requires the cash flows resulting from tax deductions in excess of the compensation cost recognized for equity awards (excess tax benefits) to be classified as financing cash flows. However, as we are not able to use these tax deductions (see Note-20, "Income Taxes" for further information), we have no excess tax benefits to be classified as financing cash flows.

Income Taxes

We are subject to income and other taxes in Peru and the United States. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, assessment of the effects of foreign taxes and domestic taxes.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the ability to realize deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine, and we have determined in the past, that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense. See Note-20, “Income Taxes.”

Foreign Exchange

The U.S. Dollar is the functional currency for our operations in both Peru and Ecuador. Ecuador has adopted the U.S. Dollar as its official currency. Peru, however, still uses its local currency, Nuevo Sol, in addition to the U.S. Dollar and therefore our financial results are subject to favorable or unfavorable fluctuations in the exchange rate and inflation of that country. We have adopted ASC Topic 830, “Foreign Currency Matters,” which requires that the translation of the applicable foreign currency into U.S. dollars be performed for balance sheet monetary accounts using current exchange rates in effect at the balance sheet date, non-monetary accounts using historical exchange rates in effect at the time the transaction occurs, and for revenue and expense accounts using a weighted average exchange rate during the period reported. Accordingly, the gains or losses resulting from such remeasurement are included in other income and expense in the consolidated Statements of Operations.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. (“ASU”) 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. We do not anticipate an impact on our financial position and results of operations.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, Revenue from Contracts with Customers, and supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In addition, ASU 2014-09 supersedes the cost guidance in Subtopic 605-35, Revenue Recognition—Construction-Type and Production-Type Contracts, and creates new Subtopic 340-40, Other Assets and Deferred Costs— Contracts with Customers. In summary, the core principle of Topic 606 is that an entity recognizes 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. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition as part of the new accounting guidance. ASU 2014-09 is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the provisions of ASU 2014-09 and assessing the impact, if any, it may have on our financial position and results of operations.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 (ASU 2014-15), which creates Subtopic 205-40, Presentation of Financial Statements— Going Concern. ASU 2014-15 requires management to assess the entity's ability to continue as a going concern, and to provide related footnote disclosures in certain circumstances. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and interim periods therein. Upon adoption, we will use this guidance to evaluate going concern.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in interest rates, oil and natural gas prices and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Interest Rate Risk

As of December 31, 2014, we had long-term debt of approximately zero and $214.3 million of current maturities of long-term debt.

During the third quarter of 2013, we closed on an offering for an aggregate of $143.8 million of 2017 Convertible Notes which includes the exercise of the underwriter's option to purchase an additional $18.8 million of the 2017 Convertible Notes.

In February and March 2010, we closed on the private offering for an aggregate $170.9 million of 2015 Convertible Notes. In September 2013, we repurchased $85.0 million of the principal balance of the $170.9 million of the 2015 Convertible Notes.

In April 2014, we exchanged $26.0 million of the aggregate principal amount of the 2015 Convertible Notes for $25.0 million aggregate principal amount of additional 2017 Convertible Notes.

The fair value of our 2017 Convertible Notes and 2015 Convertible Notes as compared to the carrying value at December 31, 2014 and December 31, 2013, was as follows:

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)		(in thousands)	
Convertible Notes, 8.5%, due October 2017, net of discount of ($13.9) million at December 31, 2014 and ($18.3) million at December 31, 2013 (1)	$ 154,839	$ 57,361	$ 125,416	$ 130,094
Convertible Notes, 6.5%, due March 2015, net of discount of ($0.4) million at December 31, 2014 and ($4.4) million at December 31, 2013 (2)	59,473	20,662	81,523	79,663

(1) We estimated the fair value of the 2017 Convertible Notes to be approximately $57.4 million and $130.1 million at December 31, 2014 and December 31, 2013, respectively, based on observed marke prices for the same or similar types of debt issues.

(2) We estimated the fair value of the 2015 Convertible Notes to be approximately $20.7 million and $79.7 million at December 31, 2014 and December 31, 2013, respectively, based on observed marke prices for the same or similar types of debt issues.

We do not expect a significant change in the market interest rate to impact the interest on our term debt. However, significant changes in market interest rates may significantly affect the level of financing that will be structured with respect to our project in Peru. Due to the voluntary filing for reorganization under Chapter 11 on March 9, 2015, the fair value of debt could be significantly impacted as a result of the lower market price of our common stock.

Commodity Price Risk

With respect to our oil and gas business, any revenues, cash flow, profitability and future rate of growth we achieve will be greatly dependent upon prevailing prices for oil and gas. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms is also expected to be dependent on oil and gas prices. Historically, oil and gas prices and markets have been volatile and are likely to continue to be volatile in the future. Prices for oil and gas are subject to potentially wide fluctuations in response to relatively minor changes in supply of and demand for oil and gas, market uncertainty, and a variety of additional factors that are beyond our control.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but may also reduce the amount of oil and natural gas we can produce economically, if any. A substantial or extended decline in oil and natural gas prices may materially affect our future business, financial condition, results of operations, liquidity and borrowing capacity, and may require a reduction in the carrying value of our oil and gas properties and other assets. While our revenues may increase if prevailing oil and gas prices increase significantly, exploration and production costs and acquisition costs for additional properties and reserves may also increase.

With respect to our planned electricity generation business, the price we can obtain from the sale of electricity through our proposed power plant may not rise at the same rate, or may not rise at all, to match a rise in the cost of production and transportation of our gas reserves which will be used to generate the electricity. Prices for electricity in Peru have been volatile in the past and may be volatile in the future. However, gas prices in Peru are regulated and therefore not volatile.

Foreign Currency Exchange Rate Risk

The U.S. Dollar is the functional currency for our operations in both Peru and Ecuador. Ecuador has adopted the U.S. Dollar as its official currency. Peru, however, uses its local currency, the Nuevo Sol, in addition to the U.S. Dollar, and therefore, our financial results are subject to favorable or unfavorable fluctuations in the exchange rate and inflation in that country. Transaction differences have been nominal to date but are expected to increase as our activities in Peru continue to escalate.

Foreign exchange gains (losses) included in the Consolidated Statement of Operations for the year ended December 31, 2014, 2013, and 2012 were approximately ($0.6) million, ($1.2) million and ($0.2) million, respectively.

We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

BPZ Resources, Inc. and Subsidiaries
Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
BPZ Resources, Inc. and Subsidiaries
Houston, Texas

We have audited the accompanying consolidated balance sheets of BPZ Resources, Inc. as of December 31, 2014 and 2013 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of BPZ Resources, Inc. at December 31, 2014 and 2013 and the results of its operations and its 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.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As described in Note 2 to the consolidated financial statements, the Company failed to make a required payment on certain of its outstanding debt obligations subsequent to December 31, 2014 and filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code on March 9, 2015 (file number 15-60016) that raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), BPZ Resources, Inc.'s internal control over financial reporting 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 and our report dated March 16, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, TX
March 16, 2015

BPZ Resources, Inc. and Subsidiaries
Consolidated Balance Sheets
(In thousands)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 62,149	$ 57,395
Accounts receivable	1,922	21,630
Income taxes receivable	2,136	2,134
Value-added tax receivable	2,343	10,490
Inventory	11,878	17,368
Restricted cash	-	1,250
Prepaid and other current assets	6,104	5,419
Total current assets	86,532	115,686
Property, equipment and construction in progress, net	165,971	217,753
Restricted cash	2,209	4,109
Other non-current assets	2,150	5,065
Investment in Ecuador property, net	501	534

Deferred tax asset		33,997		63,602
Total assets	$	291,360	$	406,749
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	4,380	$	3,127
Accrued liabilities		6,524		11,246
Other liabilities		22,533		24,494
Accrued interest payable		4,883		5,119
Derivative financial instruments		-		30
Current maturity of long-term debt		214,312		-
Total current liabilities		252,632		44,016
Asset retirement obligation		5,330		1,564
Other non-current liabilities		-		16,755
Long-term debt, net		-		206,939
Total long-term liabilities		5,330		225,258
Commitments and contingencies (Note 22 and 23)				
Stockholders' equity:				
Preferred stock, no par value, 25,000 authorized; none issued and outstanding		-		-
Common stock, no par value, 250,000 authorized; 118,657 and 117,526 shares issued and outstanding at December 31, 2014 and December 31, 2013, respectively		572,890		569,061
Accumulated deficit		(539,492)		(431,586)
Total stockholders' equity		33,398		137,475
Total liabilities and stockholders' equity	$	291,360	$	406,749

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

BPZ Resources, Inc. and Subsidiaries
Consolidated Statements of Operations
(In thousands, except per share data)

	Year Ended December 31,		
	2014	**2013**	**2012**

Net revenue:						
Oil revenue, net	$	83,464	$	50,585	$	122,708
Other revenue		433		144		250
Total net revenue		83,897		50,729		122,958
Operating and administrative expenses:						
Lease operating expense		28,571		24,893		52,458
General and administrative expense		23,730		24,111		28,705
Geological, geophysical and engineering expense		3,773		2,184		43,787
Depreciation, depletion and amortization expense		23,221		27,214		45,873
Standby costs		-		4,311		5,340
Other operating expense		4,277		4,430		2,266
Asset impairments		58,000		-		-
Gain on divestiture		-		-		(26,864)
Total operating and administrative expenses		141,572		87,143		151,565
Operating loss		(57,675)		(36,414)		(28,607)
Other income (expense):						
Income from investment in Ecuador property, net		217		152		62
Interest expense, net		(18,670)		(16,158)		(16,115)
Loss on extinguishment of debt		(1,245)		(7,222)		(7,318)
Gain (loss) on derivatives		2		242		(2,610)
Interest income		790		182		44
Other expense		(351)		(4,268)		(159)
Total other expense, net		(19,257)		(27,072)		(26,096)
Loss before income taxes		(76,932)		(63,486)		(54,703)
Income tax expense (benefit)		30,974		(5,775)		(15,614)
Net loss	$	(107,906)	$	(57,711)	$	(39,089)
Basic net loss per share	$	(0.93)	$	(0.50)	$	(0.34)
Diluted net loss per share	$	(0.93)	$	(0.50)	$	(0.34)
Basic weighted average common shares outstanding		116,311		115,943		115,631
Diluted weighted average common shares outstanding		116,311		115,943		115,631

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

BPZ Resources, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity
Years Ended December 31, 2014, 2013 and 2012
(In thousands)

	Common Stock		Accumulated	
	Shares	Amount	Deficit	Total
Balances at January 1, 2012	115,910	557,238	(334,786)	222,452
Long-term incentive compensation plans, net of forfeitures	982	2,841	-	2,841
Common stock sold for cash, net of offering costs	40	96	-	96
Net loss	-	-	(39,089)	(39,089)
Balances at December 31, 2012	116,932	560,175	(373,875)	186,300
Long-term incentive compensation plans, net of forfeitures	568	2,806	-	2,806
Common stock sold for cash, net of offering costs	26	48	-	48
Proceeds of convertible notes allocated to equity, net of debt issuance costs	-	6,032	-	6,032
Net loss	-	-	(57,711)	(57,711)
Balances at December 31, 2013	117,526	$ 569,061	$ (431,586)	$ 137,475
Exercise of stock options	99	129	-	129
Long-term incentive compensation plans, net of forfeitures	1,011	3,163	-	3,163
Common stock sold for cash, net of offering costs	21	37	-	37
Proceeds of convertible notes allocated to equity, net of debt issuance costs	-	500	-	500
Net loss	-	-	(107,906)	(107,906)
Balances at December 31, 2014	118,657	$ 572,890	$ (539,492)	$ 33,398

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

BPZ Resources, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(In thousands)

For the Year Ended

	December 31, 2014	2013	2012
Cash flows from operating activities:			
Net loss	$ (107,906)	$ (57,711)	$ (39,089)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Stock-based compensation	3,163	2,806	2,841
Depreciation, depletion and amortization	23,221	27,214	45,873
Amortization of investment in Ecuador property	33	98	188
Deferred income taxes	29,543	(9,038)	(29,165)
Loss on disposition of assets	4,277	4,430	-
Asset impairments	58,000	-	-
Loss on extinguishment of debt	1,245	7,222	7,318
(Gain) on divestiture	-	-	(26,864)
Amortization of discount and deferred financing fees	8,273	9,375	9,833
(Gain) loss on derivatives	(2)	(242)	2,610
Other non-cash items included in net loss	(33)	695	-
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	19,709	3,230	(16,349)
(Increase) decrease in value-added tax receivable	7,769	9,522	(21,259)
(Increase) decrease in inventory	5,006	2,326	(5,641)
(Increase) decrease in other assets	1,259	327	(3,379)
Decrease in income taxes receivable	59	-	-
Increase (decrease) in accounts payable	1,253	(18,852)	2,458
Increase (decrease) in accrued liabilities	(4,958)	(20,814)	12,036
Increase (decrease) in income taxes payable	-	(11,916)	11,691
Increase (decrease) in other liabilities	(18,716)	(1,299)	836
Net cash provided by (used in) operating activities	31,195	(52,627)	(46,062)
Cash flows from investing activities:			
Property and equipment additions	(29,433)	(13,472)	(82,203)
Divestiture of properties and equipment	-	-	79,299
(Increase) decrease in restricted cash	3,150	67,440	(62,934)
Proceeds from maturity of investment securities	-	1,000	-
Purchase of investment securities	-	(1,000)	-
Net cash provided by (used in) investing activities	(26,283)	53,968	(65,838)
Cash flows from financing activities:			
Borrowings	-	78,355	195,688
Repayments of borrowings	-	(99,107)	(54,919)
Deferred and other loan fees	(324)	(6,782)	(3,597)
Proceeds from exercise of stock options, net	129	-	-
Proceeds from sale of common stock, net	37	48	96

Net cash provided by (used in) financing activities		(158)		(27,486)		137,268
Net increase (decrease) in cash and cash equivalents		4,754		(26,145)		25,368
Cash and cash equivalents at beginning of period		57,395		83,540		58,172
Cash and cash equivalents at end of period	$	62,149	$	57,395	$	83,540
Supplemental cash flow information:						
Cash paid for:						
Interest	$	18,412	$	17,362	$	22,716
Income tax		1,552		14,476		1,793
Non — cash items:						
Convertible debt exchanged	$	26,000	$	72,850	$	-
Debt exchanged in divestiture for value added tax receivable		-		-		24,196
Debt exchanged in divestiture included in the $150.0 million sale proceeds		-		-		65,000
Debt exchanged in divestiture for 2012 Block Z-1 property additions		-		-		65,795
Debt transferred to current and other non-current liabilities related to 2012 Block Z-1 exploratory expenditures		-		-		40,697
Depletion allocated to production inventory		517		320		648
Depreciation on support equipment capitalized to construction in progress		-		-		472
Asset retirement obligation capitalized to property and equipment, net of revisions		3,634		1,381		1,314
Property and equipment transferred to / from current assets / liabilities or other non-current assets		-		952		-
Gain on capital lease repayment capitalized to property and equipment		-		-		180

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

BPZ RESOURCES, INC AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

Note 1 — Basis of Presentation

Organization

BPZ Resources, Inc., (together with its subsidiaries, collectively referred to as the “Company” or “BPZ” unless the context requires otherwise) a Texas corporation, is based in Houston, Texas with offices in Lima, Peru, Zorritos, Peru and Quito, Ecuador. The Company is an independent oil and gas company focused on the exploration, development and production of oil and natural gas in Peru, and to a lesser extent, Ecuador. The Company also intends to utilize part of its planned future natural gas production as a supply source for the complementary development of a gas-fired power generation facility which may be wholly-owned or partially-owned by the Company, or may be wholly-owned by a third party.

The Company maintains a subsidiary, BPZ Exploración & Producción S.R.L. ("BPZ E&P"), registered in Peru through its wholly-owned subsidiary, BPZ Energy, LLC, a Texas limited liability company, and its subsidiary, BPZ Energy International Holdings, L.P., a British Virgin Islands limited partnership. Currently, the Company, through BPZ E&P, has license agreements for oil and gas exploration and production covering a total of approximately 2.2 million gross (1.9 million net) acres, in four blocks, in northwest Peru and off the northwest coast of Peru in the Gulf of Guayaquil. The Company's license contracts cover ownership of the following properties: 51% working interest in Block Z-1 (0.6 million gross acres), 100% working interest in Block XIX (0.5 million gross acres), 100% working interest in Block XXII (0.9 million gross acres) and 100% working interest in Block XXIII (0.2 million gross acres). The Block Z-1 contract was signed in November 2001, the Block XIX contract was signed in December 2003 and the Blocks XXII and XXIII contracts were signed in November 2007. Generally, according to the Organic Hydrocarbon Law No. 26221 and the regulations thereunder (the "Organic Hydrocarbon Law" or "Hydrocarbon Law") the seven-year term for the exploration phase can be extended in each contract by up to an additional three years to a maximum of ten years. However, this exploration extension is subject to government approval and specific provisions of each license contract can vary the exploration phase of the contract as established by the Hydrocarbon Law. The license contracts require the Company to conduct specified activities in the respective blocks during each exploration period in the exploration phase. If the exploration activities are successful, the Company may decide to enter the exploitation phase and the total contract term can extend up to 30 years for oil production and up to 40 years for gas production. In the event a block contains both oil and gas, as is the case in the Company's Block Z-1 contract, the 40-year term may apply to oil production as well. The Company's estimate of proved reserves has been prepared under the assumption that the Company's license contract will allow production for the possible 40-year term for both oil and gas.

The Company owns a 10% non-operating net profits interest in an oil and gas producing property, Block 2, located in the southwest region of Ecuador (the "Santa Elena Property"). In May 2013, the license agreement and operating agreement covering the property were extended from May 2016 to December 2029.

The Company is in the process of developing its Peruvian oil and gas reserves. The Company entered commercial production for Block Z-1 in November 2010 and produces and sells oil from the Corvina and Albacora fields under the Company's current sales contracts. The Company completed the installation and permitting of the CX-15 platform in the Corvina field in November 2012 to continue the development of the field. In July 2013, the Company spudded its first development well from the CX-15 platform and have completed drilling seven wells from the CX-15 platform. The Company also spudded a new development well from the A platform in the Albacora field of Block Z-1 in September 2013 and have completed drilling four wells thereafter from the A platform. Three onshore shallow exploration wells, ranging in depth from 3,500 to 3,800 feet, have been drilled at Block XXIII during 2014. The Company is planning to pursue a long term testing program in these Block XXIII prospects, starting with Piedra Candela, and potentially sell the tested gas under a pilot program to the local communities.

On December 14, 2012, Perupetro S.A ("Perupetro"), a corporation owned by the Peruvian government empowered to become a party in the contracts for the exploration and/or exploitation of hydrocarbons in order to promote these activities in Peru, approved the terms of the amendment to the Block Z-1 License Contract to recognize the sale of a 49% participating interest ("closing") in offshore Block Z-1 to Pacific Rubiales Energy Corp. ("Pacific Rubiales"). Under the terms of the agreements signed on April 27, 2012, the Company (together with its subsidiaries) formed an unincorporated joint venture with a Pacific Rubiales subsidiary, Pacific Stratus Energy S.A., to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the agreements, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of the Company's share of capital and exploratory expenditures in Block Z-1 ("carry amount") from the effective date of the Stock Purchase Agreement ("SPA"), January 1, 2012. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of BPZ Resources, Inc. and its wholly-owned subsidiaries and branch offices. All intercompany balances and transactions have been eliminated.

The Company's accounting policy regarding partnership or joint venture interests in oil and gas properties is to consolidate such interests on a pro-rata basis in accordance with generally accepted practice in the oil and gas industry. However, the Company has not been able to receive timely information to allow it to proportionately consolidate the minority non-operating net profits interest owned by its consolidated subsidiary, SMC Ecuador Inc. See Note-9, "Investment in Ecuador Property" to the consolidated financial statements for further discussion regarding the Company's investment in its Ecuador property. Accordingly, the Company accounts for this investment under the cost method. As such, the Company records its share of cash received or paid attributable to this investment as other income or expense and amortizes its investment into income over the remaining term of the license agreement and operating agreement which were extended in May 2013 from May 2016 through December 2029. The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012 and the entitlement to crude oil production and sharing of joint operating expenditures from that day forward was allocated to each partner. At closing, the sharing of any production or joint operating expenditures prior to that date for 2012 was treated by the parties as an adjustment to the carry amount under the SPA.

Use of Estimates

The preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles ("GAAP" or "U.S. GAAP") requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses in the consolidated financial statements, and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

Estimates of crude oil reserves are the most significant of the Company's estimates. All of the reserves data in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. Numerous interpretations and assumptions are made in estimating quantities of proved crude oil and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, including impairments and asset retirement obligations and deferred income tax assets. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. Current credit market conditions combined with volatile commodity prices have resulted in increased uncertainty inherent in such estimates and assumptions. As future events and their effects cannot be determined accurately, actual results could differ significantly from management's estimates.

Reclassification

Certain reclassifications have been made to the 2013 and 2012 consolidated financial statements to conform to the 2014 presentation. These reclassifications were not material to the accompanying consolidated financial statements.

Note 2 — Liquidity and Capital Resources

The Company's consolidated financial statements have been prepared assuming that it will continue as a going concern. The conditions noted below raise substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the outcome of this uncertainty.

Voluntary Reorganization Under Chapter 11

The Company has not been profitable since it commenced operations and it requires substantial capital expenditures as the Company advances development projects at Block Z-1 and exploration projects in its other Blocks. Currently, the Company requires additional financing to continue to fund its capital expenditure program and implement its business plan. The Company's major sources of funding to date have been oil sales, equity and debt financing activities and asset sales. The increased capital costs and debt service costs in the current economic environment for the oil and gas industry have placed a strain on the Company's cash flow from operations and its ability to reduce the Company's debt leverage.

The Company currently has the following convertible notes outstanding: (i) $59.9 million principal amount of Convertible Notes due 2015 (the "2015 Convertible Notes"), which bear interest semi-annually at a rate of 6.50% per year, and (ii) $168.7 million principal amount of Convertible Notes due 2017 (the "2017 Convertible Notes"), which bear interest semi-annually at a rate of 8.50% per year. The 2015 Convertible Notes matured with repayment of approximately $62 million in principal and interest due on March 1, 2015. The Company's estimated capital and exploratory budget for 2015 calls for it to spend approximately $58.6 million in 2015 on capital and exploratory expenditures, excluding capitalized interest, for its three onshore Blocks in which the Company holds 100% working interests, and its share of the capital and exploratory expenditures for offshore Block Z-1 required under its Joint Venture Agreement with Pacific Rubiales. The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014, and the Company is now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

The price of oil per barrel has dropped dramatically, particularly in the fourth quarter 2014 and continuing in the first quarter 2015, by more than half since its high in June 2014. In mid-October 2014, the Company withdrew its previously announced private placement offer of $150.0 million in senior secured notes due 2019 due to adverse market conditions.

On December 8, 2014, the Company received a notification from the New York Stock Exchange ("NYSE") that the Company had fallen below the NYSE's continued listing standard relating to minimum share price, which requires a minimum average closing price of $1.00 per share over 30 consecutive trading days. The price has remained well below such threshold and the NYSE subsequently notified the Company on March 2, 2015 that it had determined to commence proceedings to delist its common stock.

As a result of the aforementioned events and circumstances, in December 2014 the Company engaged the services of Houlihan Lokey Capital Inc. (the "Advisors") to assist it in analyzing various strategic alternatives and addressing the Company's liquidity and capital structure, and formed a special committee of the Board of Directors to work with the Advisors. The Company engaged in discussions with representatives of its various debt holders regarding, among other items, the potential terms under which one or both bond issues could be restructured to provide a capital structure which would allow the Company to continue developing its oil and gas assets. The Company has also pursued discussions with other potential investors regarding alternative financing solutions. The Company decided that it was in the best long-term interest of all stakeholders, both credit and equity holders, to expeditiously address the Company's capital structure with the goal of reducing debt and the cost of capital to position the Company for the future, and on March 2, 2015 announced that it had decided not to pay approximately $62 million in principal and interest due on March 1, 2015 on its 2015 Convertible Notes and to use a 10-day grace period on principal due and a 30-day grace period on interest due to continue discussions with its debt holders.

The Company was unable to reach a mutually agreeable solution within the grace period for the principal amount due on the 2015 Convertible Notes and elected not to make the approximate $59.9 million in principal payment due at the end of the grace period for principal due. As a result, the Company is in default under the 2015 Convertible Notes, permitting the trustee for the 2015 Convertible Notes or the holders of at least 25% in aggregate principal amount of the outstanding 2015 Convertible Notes to declare the full amount of the principal and interest thereunder immediately due and payable. If the 2015 Convertible Notes were to be accelerated, an event of default would occur under the indenture for the 2017 Convertible Notes, permitting the trustee or the holders of at least 25% in aggregate principal amount of the outstanding 2017 Convertible Notes to also declare the full amount of the principal and interest thereunder immediately due and payable.

On March 9, 2015 (the "Petition Date"), BPZ Resources, Inc. (the "Debtor") filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court") to provide more time to find an appropriate solution to its financial situation and implement a plan of reorganization aimed at improving its capital structure. The Chapter 11 case is being administered by the Bankruptcy Court as Case No. 15-60016.

The filing of the Chapter 11 case constituted an event of default that triggered repayment obligations under the 2015 Convertible Notes and the 2017 Convertible Notes. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

Since the Petition Date, the Debtor has operated its business as a "debtor-in-possession" pursuant to Sections 1107(a) and 1108 of the Bankruptcy Code, which will allow the Debtor to continue operations during the reorganization proceedings. The Debtor will remain in possession of its assets and properties, and its business and affairs will continue to be managed by its directors and officers, subject in each case to the supervision of the Bankruptcy Court.

None of the Debtor's direct or indirect subsidiaries or affiliates has filed for reorganization under Chapter 11 and none is expected to file for reorganization or protection from creditors under any insolvency or similar law in the U.S. or elsewhere. The Debtor's subsidiaries will continue to operate outside of any reorganization proceedings. The Company therefore does not expect the Debtor's filing of Chapter 11 protection to impact its license agreements.

On the day after the Petition Date, the Debtor obtained approval from the Bankruptcy Court for a variety of "first day" motions to give the Debtor the authority to take a broad range of actions, including, among others, authority to maintain bank accounts and the cash management system, pay certain employee obligations, post-petition utilities and other customary relief.

In addition, the Company's auditors have expressed substantial doubt about its ability to continue as a going concern. See the Report of Independent Registered Public Accounting Firm included under Item 8. "Financial Statements and Supplementary Data."

Note 3 — Significant Accounting Policies

Revenue Recognition

The Company recognizes revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the seller's price to the buyer is fixed or determinable, and (iv) collectability is reasonably assured.

The Company sells its production in the Peruvian domestic market on a contract basis. Revenue is recorded net of royalties when the purchaser takes delivery of the oil. At the end of the period, oil that has been produced but not sold is recorded as inventory at the lower of cost or market. Cost is determined on a weighted average based on production costs. See Note–17, "Revenue" for further information.

Reporting and Functional Currency

The U.S. Dollar is the functional currency for the Company's operations in both Peru and Ecuador. Ecuador has adopted the U.S. Dollar as its official currency. Peru, however, uses its local currency, Nuevo Sol, in addition to the U.S. Dollar and therefore its financial results are subject to foreign currency gains and losses. The Company has adopted Accounting Standard Codification ("ASC") Topic 830, "Foreign Currency Matters," which requires that the translation of the applicable foreign currency into U.S. dollars be performed for balance sheet monetary accounts using current exchange rates in effect at the balance sheet date, non-monetary accounts using historical exchange rates in effect at the time the transaction occurs, and for revenue and expense accounts using a weighted average exchange rate during the period reported. Accordingly, the gains or losses resulting from such remeasurement are included in other income and expense in the consolidated statements of operations. Foreign exchange gains (losses) for the year ended December 31, 2014, 2013, and 2012 were approximately ($0.6) million, ($1.2) million and ($0.2) million, respectively.

Cash and Cash Equivalents

The Company considers cash on hand, cash in banks, money market mutual funds and highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. Certain of the Company's cash balances are maintained in foreign banks which are not covered by deposit insurance. The cash balance in the Company's U.S. bank accounts may exceed federally insured limits.

Restricted Cash and Performance Bonds

As discussed in Note-10, "Restricted Cash and Performance Bonds," the Company has secured various performance bonds, collateralized by certificates of deposit, to guarantee its obligations and commitments in connection with its exploratory properties in Peru. All of the performance bonds have been issued by Peruvian banks and their terms are dictated by the corresponding license contract or agreement. As a result of the repayment of the remaining principal balance of the $40.0 million secured debt facility in September 2013, it was agreed that the restricted cash balance of $1.0 million would remain relating to the performance based arranger fee (the "Performance Based Arranger Fee") for the $75.0 million secured debt facility through July 2014. In July 2014 the $1.0 million was released to the Company and the debt service reserve account was terminated.

Accounts Receivable and Allowance for Doubtful Accounts

Currently, the Company's contract terms regarding oil sales have a relatively short settlement period. Also included in accounts receivable are amounts receivable from the Company's joint venture partner. The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for balances greater than 90 days outstanding. Currently, the majority of oil sale receivables are current or were outstanding less than thirty days.

It is the Company's belief that there are no balances in accounts receivable that will not be collected and that an allowance was not necessary at December 31, 2014 and December 31, 2013, respectively.

Inventories

Inventories consist of crude oil, tubular goods, accessories and spare parts for production equipment used in the Company's oil and gas operations, stated at the lower of average cost or market. The cost of crude oil inventory includes production costs and depreciation, depletion and amortization of oil and gas properties. See Note-6, "Inventory."

Property, Equipment and Construction in Progress

The Company follows the successful efforts method of accounting for its costs of acquisition, exploration and development of oil and gas properties. Under this method, oil and gas lease acquisition costs and intangible drilling costs associated with exploration efforts that result in the discovery of proved reserves and costs associated with development drilling, whether or not successful, are capitalized when incurred. Capitalized costs of producing crude oil and natural gas properties, along with support equipment and facilities, are amortized to expense by the unit-of-production method based on proved developed crude oil reserves on a field-by-field basis. Certain costs of exploratory wells are capitalized pending determinations that proved reserves have been found. Exploratory well costs continue to be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If the determination is dependent upon the results of planned additional wells and required capital expenditures to produce the reserves found, the drilling costs will be capitalized as long as sufficient reserves have been found to justify completion of the exploratory well and additional wells are underway or firmly planned to complete the evaluation of the well. All costs related to unsuccessful exploratory wells are expensed when such wells are determined to be non-productive.

In January 2013, the Company made a change in its method of estimating the depreciation of producing equipment. The Company changed to the unit-of-production method from a straight-line five-year life method of calculating depreciation because it more accurately matches the costs of production equipment to the Company's oil production.

The Company assesses its capitalized exploratory wells pending evaluation each quarter to determine whether costs should remain capitalized or should be charged to earnings. Other exploration costs, including geological, geophysical and engineering costs, are expensed as incurred. The Company recognizes gains or losses on the sale of properties, should they occur, on a field-by-field basis.

Projects under construction are not depreciated or amortized until placed in service. For assets the Company constructs, it capitalizes direct costs, such as labor and materials, and indirect costs, such as overhead and interest. The Company periodically evaluates the recoverability of the carrying value of its long-lived assets by monitoring and evaluating changes in circumstances that may indicate that the carrying amount of the asset may not be recoverable and subsequently expensed. As of December 31, 2014, property and equipment consists of office equipment, vehicles and leasehold improvements made to the Company's offices. All such values are stated at cost and are depreciated on a straight-line basis over the estimated useful life of the assets which ranges between three and ten years, or if shorter the term of the lease. Vessels and related equipment are depreciated on a straight-line basis over the estimated useful life of the asset, which is between two and fifteen years. Maintenance and repairs are expensed as incurred. Replacements, upgrades or expenditures which improve and extend the life of the assets are capitalized. When assets are sold, retired or otherwise disposed, the applicable costs and accumulated depreciation and amortization are removed from the appropriate accounts and the resulting gain or loss is recorded.

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities at December 31, 2014 and 2013 consisted mainly of accounts payable and accrued liabilities related to costs for which goods and services have been received in support of the Company's oil and gas operations, including drilling operations, seismic, lease operating costs and amounts payable to the Company's joint venture partner.

Other Current Liabilities

Other current liabilities included in the Company's balance sheet at December 31, 2014 and December 31, 2013 includes $22.5 million and $23.9 million, respectively, related to exploratory expenditures for Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount is being settled by the Company and Pacific Rubiales under the terms of the SPA with cash payments under the liability of $14.4 million occurring in 2014.

Asset Retirement Obligation

Asset retirement obligations consist of estimated costs of well plugging and abandonment, dismantlement, removal, site reclamation and similar activities associated with the Company's oil and gas properties. The Company recognizes the fair value of a liability for an ARO in the period in which it is incurred when it has an existing legal obligation associated with the retirement of its oil and gas properties that can reasonably be estimated, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The fair value of the asset retirement obligation asset and liability is measured using expected future cash outflows discounted at the Company's credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted using the units of production method. Should either the estimated life or the estimated abandonment costs of a property change materially upon the Company's periodic review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using the Company's credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. Any negative adjustment in excess of asset retirement cost is reclassified to depreciation, depletion and amortization expense. See Note-11, "Asset Retirement Obligation."

Other Non-current Liabilities

The other non-current liabilities included in the Company's balance sheet at December 31, 2014 and December 31, 2013 includes zero and $16.8 million, respectively, related to exploratory expenditures for Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount will be settled by the Company and Pacific Rubiales under the terms of the SPA.

Oil and Gas Accounting Reserves Determination

The successful efforts method of accounting depends on the estimated reserves the Company believes are recoverable from its oil and gas reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, the Company incorporates many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

The Company believes its assumptions are reasonable based on the information available to it at the time it prepared the estimates. However, these estimates may change substantially going forward as additional data from development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with the Securities and Exchange Commission ("SEC") requirements and generally accepted industry practices in the US as prescribed by the Society of Petroleum Engineers. Reserve estimates are independently evaluated at least annually by independent qualified reserves engineers, Netherland, Sewell & Associates, Inc ("NSAI"). The estimate of the Company's proved reserves as of December 31, 2014 and 2013 has been prepared and presented in accordance with SEC rules and accounting standards. These rules require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing.

The Company's Technical Committee of the Board of Directors oversees the review of its oil and gas reserves and related disclosures prepared by the Company's appointed independent reserve engineers. The Technical Committee meets with management periodically to review the reserves process and results, and to confirm that the independent reserve engineers have had access to sufficient information, including the nature and satisfactory resolution of any material differences of opinion between the Company and the reserve engineers.

Reserves estimates are critical to many of the Company's accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves;
- calculating the Company's unit-of-production depletion rates. Proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating the Company's depletion expense; and
- assessing, when necessary, the Company's oil and gas assets for impairment using undiscounted future cash flows based on management's estimates. If impairment is indicated, discounted values will be used to determine the fair value of the assets. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Impairment of Long-Lived Assets

The Company periodically evaluates the recoverability of the carrying value of its long-lived assets by monitoring and evaluating changes in circumstances that may indicate that the carrying amount of the asset may not be recoverable. Examples of events or changes in circumstances that indicate that the recoverability of the carrying amount of an asset should be assessed include but are not limited to the following: a significant decrease in the market value of an asset, a significant change in the extent or manner in which an asset is used or a significant physical change in an asset, a significant adverse change in legal factors or in the business climate that could affect the value of an asset or an adverse action or assessment by a regulator, an accumulation of costs significantly in excess of the amount originally expected to acquire or construct an asset, and/or a current period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with an asset used for the purpose of producing revenue.

The Company considers historical performance and anticipated future results in its evaluation of potential impairment. Accordingly, when indicators of impairment are present, the Company evaluates the carrying value of these assets in relation to the operating performance of the business and future discounted and non-discounted cash flows expected to result from the use of these assets. Impairment losses are recognized when the expected future cash flows from an asset are less than its carrying value. For the year ended December 31, 2014, the Company recognized $58.0 million of impairment losses. For the year ended December 31, 2013 and 2012, there were no impairment losses recognized by the Company.

Stock Based Compensation

The Company accounts for stock-based compensation at fair value in accordance with the provisions of ASC Topic 718, "Stock Compensation" ("ASC Topic 718"), which establishes accounting for stock-based payment transactions for employee services and goods and services received from non-employee directors. Under the provisions of ASC Topic 718, stock-based compensation cost is measured at the date of grant, based on the calculated fair value of the award, and is recognized as expense in the Consolidated Statements of Operations ratably over the employee's or non-employee director's requisite service period, which is generally the vesting period of the equity grant. The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of the Company's common stock on the grant date. The fair value of the performance stock units is determined using a Monte Carlo simulation model on the grant date. Additionally, stock-based compensation cost is recognized based on awards that are ultimately expected to vest, therefore, the compensation cost recognized on stock-based payment transactions is reduced for estimated forfeitures based on the Company's historical forfeiture rates. Additionally, no stock-based compensation costs were capitalized for the year ended December 31, 2014, 2013 and 2012. The Company provides compensation benefits to employees and non-employee directors under stock-based payment arrangements, including various employee stock option plans. See Note-14, "Stockholders' Equity," for further discussion of the Company's stock-based compensation plans.

ASC Topic 230, "Statement of Cash Flows," requires the cash flows resulting from tax deductions in excess of the compensation cost recognized for equity awards (excess tax benefits) to be classified as financing cash flows. However, as the Company is not able to use these tax deductions (see Note-20, "Income Taxes" for further information), it has no excess tax benefits to be classified as financing cash flows.

Capitalized Interest

Certain interest costs have been capitalized as part of the cost of oil and gas properties under development, including wells in progress and related facilities. Total interest costs capitalized during the year ended December 31, 2014, 2013 and 2012 were $9.2 million, $9.9 million and $15.6 million, respectively.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash, restricted cash, trade receivables, trade payables, debt and derivatives. The book values of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of those instruments. For further information regarding the fair value of the Company's fixed rate debt see Note-15, "Fair Value Measurements and Disclosures." The Company's derivative financial instruments consist of variable financing arranger fee payments that are dependent on the change in oil prices from the loan origination date of the Company's variable rate debt and the oil price on each repayment date. The Company estimates the fair value of these payments based on published forward commodity price curves at each financial reporting date. The variable financing arranger fee payments expired in July 2014.

Income Taxes

The Company accounts for income taxes in accordance with ASC Topic 740, "Income Taxes." Under ASC Topic 740, deferred tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

Environmental

The Company is subject to environmental laws and regulations of various U.S. and international jurisdictions. These laws and regulations, which are subject to change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

Environmental costs that relate to current operations are expensed or capitalized as appropriate. Costs are expensed when they relate to an existing condition caused by past operations and will not contribute to current or future revenue generation. Liabilities related to environmental assessments and/or remedial efforts are accrued when property or services are provided and when such costs can be reasonably estimated. The Company's cost for environmental impact assessments related to the Company's properties included in geological, geophysical and engineering expense for the year ended December 31, 2014, 2013 and 2012 were approximately $0.8 million, $0.3 million and $0.5 million, respectively.

Loss per Common Share

In accordance with provisions of ASC Topic 260, "Earnings per Share," basic earnings (loss) per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted earnings per share is computed based upon the weighted-average number of common shares outstanding plus the assumed issuance of common shares for all potentially dilutive securities. Diluted loss per share equals basic loss per share for the periods presented because the effects of potentially dilutive securities are antidilutive.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. ("ASU") 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. The Company does not anticipate an impact to its financial position and results of operations.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, Revenue from Contracts with Customers, and supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In addition, ASU 2014-09 supersedes the cost guidance in Subtopic 605-35, Revenue Recognition—Construction-Type and Production-Type Contracts, and creates new Subtopic 340-40, Other Assets and Deferred Costs— Contracts with Customers. In summary, the core principle of Topic 606 is that an entity recognizes 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. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition as part of the new accounting guidance. ASU 2014-09 is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). The Company is currently evaluating the provisions of ASU 2014-09 and assessing the impact, if any, it may have on its financial position and results of operations.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 (ASU 2014-15), which creates Subtopic 205-40, Presentation of Financial Statements— Going Concern. ASU 2014-15 requires management to assess the entity's ability to continue as a going concern, and to provide related footnote disclosures in certain circumstances. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and interim periods therein. Upon adoption, the Company will use this guidance to evaluate going concern.

Note 4 — Divestiture

On April 27, 2012, the Company and Pacific Rubiales (together with its subsidiaries) executed a SPA under which the Company formed an unincorporated joint venture with Pacific Rubiales to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the SPA, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of the Company's share of capital and exploratory expenditures in Block Z-1 from the effective date of the SPA, January 1, 2012. In order to finalize the joint venture, Peruvian governmental approvals were needed to allow Pacific Rubiales to become a party to the Block Z-1 License Contract. Until the required approvals were obtained, Pacific Rubiales provided a $65.0 million down payment on the purchase price and other funds which the Company initially accounted for as loans to continue to fund the Company's Block Z-1 capital and exploratory activities. These amounts were reflected as long-term debt prior to closing the transaction. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

The development of Block Z-1 is subject to the terms and conditions of a Joint Operating Agreement with Pacific Rubiales that governs the legal, technical and operating rights and obligations of the parties with respect to the operation of Block Z-1. Under the agreement, the Company is the operator and responsible for the administrative, regulatory, government and community related duties, and Pacific Rubiales manages the technical and operating duties in Block Z-1. The Joint Operating Agreement will continue for the term of the License Contract and thereafter until all decommissioning obligations under the License Contract have been satisfied.

At closing, Pacific Rubiales exchanged certain loans along with an additional $85.0 million, plus other amounts due to the Company or from the Company under the SPA, for the interests and assets obtained from the Company under the SPA and under the Block Z-1 License Contract. Proceeds of $150.0 million (less transaction costs of $5.7 million) less the net book value of the assets resulting in a gain on the sale of $26.9 million for the year ended December 31, 2012, which was recognized as a component of operating and administrative expenses in connection with the closing. Due to certain tax benefits resulting from the sale, the after tax gain was $31.1 million.

The transaction provided for an adjustment based upon the collection of revenues ($56.1 million) and the payment of expenses ($32.6 million) and income taxes ($5.2 million) attributable to the properties that took place after the effective date of January 1, 2012 and prior to the closing date which was December 14, 2012. These amounts were considered settled by adjusting down $18.3 million of the unused portion of the carry amount.

The carry amount Pacific Rubiales agreed to pay under the joint venture was completed in December 2014 and we are now responsible for funding our full share of capital expenditures and joint operating expenditures for Block Z-1.

The December 31, 2013 carry amount was $81.3 million.

At December 31, 2014 and December 31, 2013, the Company reflected $22.5 million and $23.9 million, respectively, as other current liabilities and zero and $16.8 million, respectively, as other non-current liabilities for exploratory expenditures related to Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount is being settled by the Company and Pacific Rubiales under the terms of the SPA with cash payments under the liability of $14.4 million occurring in 2014.

Note 5 — Receivables, Accounts Payable and Accrued Liabilities

Accounts Receivable

Below is a summary of accounts receivable as of December 31, 2014 and December 31, 2013:

	December 31, 2014	December 31, 2013

	(in thousands)	
Commodity sales	$ 1,473	$ 2,303
Accounts receivable - joint venture	-	12,230
Other	449	7,097
Accounts receivable	$ 1,922	$ 21,630

At December 31, 2014 and December 31, 2013, accounts receivable other consisted of $0.3 million and $7.0 million due to the Company from the Company's joint venture partner for services and materials provided directly to the joint venture partner.

Income Taxes Receivable

The Company's December 31, 2014 and December 31, 2013 income tax receivable amounts were $2.1 million.

Value-Added Tax Receivable

Value-added tax (referred to as "IGV" in Peru) is generally imposed on goods and services at a rate of 18%.

The Company is recovering its IGV receivable with IGV payables associated with oil sales under the normal IGV recovery process.

Activity related to the Company's value-added tax receivable for December 31, 2014 and 2013 is as follows:

	December 31, 2014	December 31, 2013
	(in thousands)	
Value-added tax receivable as of the beginning of the period	$ 12,262	$ 21,784
IGV accrued related to expenditures during period	13,943	12,722
IGV reduced related to sale of oil during period	(21,712)	(22,244)
Value-added tax receivable as of the end of the period	$ 4,493	$ 12,262
Current portion of value-added tax receivable as of the end of the period	$ 2,343	$ 10,490
Long-term portion of value-added tax receivable as of the end of the period	$ 2,150	$ 1,772

See Note-7, “Prepaid and Other Current Assets and Other Non-Current Assets” for further information on the long-term portion of the value-added tax receivable.

Accounts Payable and Accrued Liabilities

Below is a summary of accounts payable as of December 31, 2014 and December 31, 2013:

	December 31, 2014	December 31, 2013
	(in thousands)	
Accounts payable - joint venture	$ 2,947	$ -
Other accounts payable	1,433	3,127
Accounts payable	$ 4,380	$ 3,127

The December 31, 2014 and December 31, 2013 accrued liabilities amounts were $6.5 million and $11.2 million, respectively.

Note 6 — Inventory

Inventories consist of crude oil, tubular goods, accessories and spare parts for production equipment, stated at the lower of average cost or market.

The Company maintains crude oil inventories in storage vessels until the inventory quantities are at a sufficient level to make a delivery to the refinery in Talara. Crude oil inventory is stated at the lower of average cost or market value. Cost is determined on a weighted average basis based on production costs.

Below is a summary of inventory as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	(in thousands)	
Tubular goods, accessories and spare parts	$ 9,854	$ 15,534
Crude oil	2,024	1,834
Inventory	$ 11,878	$ 17,368

	December 31,	December 31,

	2014	2013
Crude oil (barrels)	42,087	24,866
Crude oil (cost per barrel)	$ 48.09	$ 73.77

Note 7 — Prepaid and Other Current Assets and Other Non-Current Assets

Below is a summary of prepaid and other current assets as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	(in thousands)	
Prepaid expenses and other	$ 3,184	$ 4,327
Prepaid insurance	976	1,092
Debt issue costs, net	1,944	-
Prepaid and other current assets	$ 6,104	$ 5,419

Prepaid expenses and other are related to prepayments for drilling services, equipment rental and material procurement, debt issue costs, net and deposits that are rent deposits in connection with the Company's offices in Houston and Peru. Prepaid insurance consists of premiums related to the Company's operations as well as general liability and directors' and officers' insurance policies.

Below is a summary of other non-current assets as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	(in thousands)	
Debt issue costs, net	$ -	$ 3,293
Value-added tax receivable	2,150	1,772
Other non-current assets	$ 2,150	$ 5,065

Debt issue costs, net, consist of direct transaction costs incurred by the Company in connection with its debt raising efforts, less the amortization of the debt issuance costs to date.

As a result of the Company being in default under the 2015 Convertible Notes and the 2017 Convertible Notes and the Company's voluntarily filing for reorganization under the Chapter 11 of the Bankruptcy Code on March 9, 2015, the Company's debt issue costs has been classified as a current asset. Based on the outcome of the Bankruptcy Court proceedings, the debt issue costs may have no future benefit to the Company and may be written off.

The debt issue costs, net associated with the 2015 Convertible Notes and the 2017 Convertible Notes were $0.1 million and $1.8 million at December 31, 2014, and these amounts were classified as current assets. The debt issue costs, net associated with the 2015 Convertible Notes and the 2017 Convertible Notes were $1.1 million and $2.2 million at December 31, 2013, and these amounts were classified as non-current assets.

The following table shows the amount of debt issue costs amortized into interest expense for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
	(in thousands)		
Amortization of debt issue costs	$ 1,372	$ 2,365	$ 3,135

For further information regarding the Company's debt, see Note-12, "Debt Obligations."

At December 31, 2014 and December 31, 2013, the Company classified $2.2 million and $1.8 million, respectively, of its value-added tax receivable balance as a long-term asset as it believed it would take longer than one year to receive the benefit of this portion of the value-added tax receivable. For further information see Note-5, "Receivables, Accounts Payable and Accrued Liabilities."

Note 8 — Property, Equipment and Construction in Progress

Below is a summary of property, equipment and construction in progress as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	(in thousands)	
Construction in progress:		
Power plant and related equipment	$ 32,801	$ 82,928
Platforms and wells	30,363	12,505
Pipelines and processing facilities	892	846
Other	216	556
Producing properties (successful efforts method of accounting)	147,071	140,937
Producing equipment	40,315	40,209
Barge and related equipment	34,289	53,969
Office equipment, leasehold improvements and vehicles	9,131	9,122
Accumulated depletion, depreciation and amortization	(129,107)	(123,319)
Property, equipment and construction in progress, net	$ 165,971	$ 217,753

Suspended Exploratory Well Costs

Exploratory well costs capitalized greater than one year after completion of drilling were $6.6 million as of December 31, 2014, and December 31, 2013. The exploratory well costs relate to the CX11-16X gas well that was drilled in 2007, which tested sufficient quantities of gas and is currently shut-in until such time as a market is established for selling the gas. The Company plans to use the gas from the CX11-16X well for its gas-to-power project. See Note-22, "Commitments and Contingencies" for further information on the gas-to-power project.

Capital Expenditures

During the year ended December 31, 2014, the Company incurred net capital expenditures of approximately $33.1 million associated with its development initiatives for the exploration and production of oil and natural gas reserves and the complementary development of gas-fired power generation of electricity for sale in Peru.

Approximately $2.4 million was transferred from construction in progress to producing properties for the year ended December 31, 2014.

The capital expenditures added were approximately $18.8 million related to the exploration of Block XXIII, which included capitalized interest of $1.6 million, approximately $7.7 million of costs related to the power plant, which consisted of capitalized interest of $7.1 million, and other capital expenditures incurred of approximately $6.6 million (which includes $1.8 million related to Block Z-1), which included capitalized interest of $0.5 million.

The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012. Pacific Rubiales provided funding for capital expenditures for Block Z-1 of $177.9 million for the year ended December 31, 2014. The gross capital expenditures of Block Z-1 include approximately $63.5 million related to the CX-15 development drilling program, approximately $61.0 million related to the development drilling program in Albacora and expenditures related to the Delfin platform of approximately $18.4 million, the Piedra Redonda platform of approximately $14.8 million and the CX-15 platform of approximately $2.8 million.

During the year ended December 31, 2013, the Company incurred net capital expenditures of approximately $13.5 million associated with its development initiatives for the exploration and production of oil and natural gas reserves and the complementary development of gas-fired power generation of electricity for sale in Peru.

Approximately $13.5 million was transferred from construction in progress to producing properties for the year ended December 31, 2013.

During the year ended December 31, 2013, the Company incurred capital expenditures of approximately $8.8 million of costs related to the power plant, which consisted of capitalized interest of $8.0 million, approximately $2.4 million related to the Block XXIII exploratory drilling program, and capital expenditures incurred related to marine, information technology and other projects of $2.3 million, which included capitalized interest of $1.9 million.

The transfer of a 49% participating interest in Block Z-1 to Pacific Rubiales was effective on December 14, 2012. Pursuant to the carry agreement, Pacific Rubiales provided funding for 100% of capital expenditures for Block Z-1 of $80.6 million for the year ended December 31, 2013. These gross capital expenditures includes approximately $38.6 million related to the CX-15 development drilling program, $17.9 million related to the development drilling program at Albacora, the costs incurred in the design, fabrication, installation and pipeline connections related to the CX-15 platform of approximately $14.1 million and $4.2 million associated with the Corvina offshore Lease Automatic Custody Transfer unit.

Asset Impairments

In connection with the Company’s periodic evaluation of assets for recoverability, the Company revised its view of the Power plant and related equipment, due to recent developments that may change the extent or manner in which the asset may be used. Using a probability weighted average income approach of different courses of action available to the Company, the Company compared the undiscounted cash flows to the carrying value of the assets. The fair value of the assets was determined using discounted cash flow models using the same methodology. As a result, the assets are considered to be impaired, and the Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets. The Company recorded an impairment loss related to Power plant and related equipment $58.0 million in 2014. See Note-15, "Fair Value Measurements and Disclosures" for further information.

In January 2013, the Company made a change in its method of estimating the depreciation of producing equipment. The Company changed to the unit-of-production method from a straight-line five-year life method of calculating depreciation because it more accurately matches the costs of production equipment to the Company's oil production. If the Company had continued using a straight-line five-year life method, depreciation, depletion and amortization expense would have been $1.4 million higher for the year ended December 31, 2013.

The following table shows the amount of interest expense capitalized to construction in progress for the year ended December 31, 2014 and 2013, respectively:

	Year Ended December 31, 2014	Year Ended December 31, 2013
	(in thousands)	
Interest expense capitalized	$ 9,250	$ 9,858

Note 9 — Investment in Ecuador Property

The Company has a 10% non-operating net profits interest in the Santa Elena Property, an oil and gas property in Ecuador. The Company accounts for this investment under the cost method and records its share of cash received as other income. Since the Company's investment represents ownership of an oil and gas property, which is a depleting asset, the Company is amortizing the cost of the investment on a straight-line basis over the remaining term of the agreement, which expires in December 2029.

Below is a summary reflecting the Company's income from the investment in the Ecuador property for the year ended December 31, 2014, 2013 and 2012, respectively, and the investment in the Ecuador property at December 31, 2014 and 2013, respectively:

	Year Ended December 31, 2014	2013	2012
		(in thousands)	
Distributions received from investment in Ecuador property	$ 250	$ 250	$ 250
Amortization of investment in Ecuador property	(33)	(98)	(188)
Income from investment in Ecuador property, net	$ 217	$ 152	$ 62

	December 31, 2014	December 31, 2013
	(in thousands)	

Investment in Ecuador property, net	$	501	$	534

In 2013, in order to extend the term of the contract from 2016 to 2029, the Consortium, which includes the Company and three other partners, agreed to additional work commitments to increase production in the Santa Elena field. The Company's total share of this commitment over the remaining life of the contract is $4.8 million (the Company's 10% non-operating net profits interest) which amount is due throughout the period of 2015 through 2028. This commitment is expected to be funded by cash on hand, cash generated from new production, or loans of the Consortium. If the Consortium does not have sufficient cash on hand, the Company may elect to make a cash contribution to the Consortium for its 10% share of the commitment. If the Company elects not to make its 10% share contribution of the commitment, it would lose its rights in the Consortium and the contract for the Santa Elena field.

In the fourth quarter of 2014, the Consortium incurred a loan for the additional work commitments to increase production in the Santa Elena field. The Consortium loan is to be paid with cash generated from the production of the Santa Elena Field. The Company's total share of this loan would be $1.0 million (our 10% non-operating net profits interest) which amounts are due quarterly through the fourth quarter of 2017. If the Consortium does not have sufficient cash on hand, the Company would make a cash contribution to the Consortium for its 10% share of this loan.

Note 10 — Restricted Cash and Performance Bonds

Below is a summary of restricted cash as of December 31, 2014 and December 31, 2013:

	December 31, 2014		December 31, 2013	
	(in thousands)			
Performance bonds totaling $5.7 million for properties in Peru	$	1,559	$	3,459
Performance obligations and commitments for the gas-to-power site		650		650
Secured letters of credit		-		250
$40.0 million secured debt facility		-		1,000
Unsecured performance bond totaling $0.1 million for office lease agreement		-		-
Restricted cash	$	2,209	$	5,359
Current portion of restricted cash as of the end of the period	$	-	$	1,250
Long-term portion of restricted cash as of the end of the period	$	2,209	$	4,109

The $75.0 million secured debt facility entered into by the Company in July 2011 required the Company to establish a $2.5 million debt service reserve account during the first 15 months the debt facility was outstanding. After the first 15-month period, the Company was required to keep a balance in the debt service reserve account equal to the aggregate amount of principal and interest due on the next quarterly repayment date. The requirement was subsequently amended subject to the closing of the sale of a 49% participating interest in Block Z-1 to require the funding of the debt service reserve account related to the $75.0 million secured debt facility in the amount of outstanding principal. The remaining principal balance related to the $75.0 million secured debt facility was repaid in May 2013 utilizing the funds in the debt service reserve account related to this debt facility, bringing both the current and non-current balances to zero at December 31, 2013.

The $40.0 million secured debt facility entered into by the Company in January 2011 required the Company to establish a $2.0 million debt service reserve account during the first 18-month period and, thereafter, to maintain a balance in the debt service reserve account equal to the aggregate amount of principal and interest payment on the $40.0 million secured debt facility due on the succeeding principal repayment date. The requirement was amended subject to the closing of the sale of a 49% participating interest in Block Z-1 to increase the funding of the debt service reserve account related to the $40.0 million secured debt facility to the amount of outstanding principal. The requirement was subsequently changed when the Company amended and restated the $40.0 million secured debt facility in May 2013 for the Company to maintain a balance in the debt service reserve account equal to the aggregate amount of principal and interest payment on the $40.0 million secured debt facility due on the succeeding principal repayment date. The remaining principal balance related to the $40.0 million secured debt facility was repaid in September 2013 utilizing $3.8 million of funds from the debt service reserve account related to this debt facility. As a result of the repayment of the remaining principal balance of the $40.0 million secured debt facility, it was agreed that the restricted cash balance would remain at $1.0 million relating to the Performance Based Arranger Fee for the $75.0 million secured debt facility through July 2014. In July 2014 the $1.0 million was released to the Company and the debt service reserve account was terminated. Therefore, the restricted cash balance related to the current and non-current portion of the $40.0 million secured debt financing were both zero at December 31, 2014. The restricted cash balance related to the current and non-current portion of the $40.0 million secured debt financing was $1.0 million and none, respectively, at December 31, 2013.

All of the performance and insurance bonds are issued by Peruvian banks and their terms are governed by the corresponding license contracts, customs laws, legal requirements or rental practices.

Note 11 — Asset Retirement Obligation

An obligation was recorded for the future plug and abandonment of the oil wells in the Corvina and Albacora fields in Block Z-1, the Pampa la Gallina well in Block XIX, the Caracol 1X well, the Cardo 2X well and the Piedra Candela 3X well in Block XXIII in accordance with the provisions of ASC Topic 410, “Asset Retirement and Environmental Obligations.” ASC 410-20 requires that an asset retirement obligation (“ARO”) associated with the retirement of a tangible, long-lived asset be recognized as a liability in the period in which it is incurred and becomes determinable. Under this method, when liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and natural gas properties is increased. The fair value of the ARO asset and liability is measured using expected future cash outflows discounted at the Company’s credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted using the units of production method. Should either the estimated life or the estimated abandonment costs of a property change materially upon the Company’s periodic review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using the Company’s credit-adjusted-risk-free rate. The carrying value of the ARO is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. Any negative adjustment in excess of asset retirement cost is reclassified to depreciation, depletion and amortization expense.

Activity related to the Company’s ARO for the year ended December 31, 2014 and December 31, 2013 is as follows:

	December 31, 2014	December 31, 2013
	(in thousands)	
ARO as of the beginning of the period	$ 1,564	$ 2,708

Liabilities incurred during period	2,800	204
Accretion expense	133	238
Revisions in estimates during period	833	(1,586)
ARO as of the end of the period	$ 5,330	$ 1,564

The 2014 and 2013 revisions in estimates are due to the change in estimates of future costs and the shift in timing of cash flows associated with expected payment of the ARO liability. As revisions to estimated costs both in 2014 and 2013, the present value of the liabilities was adjusted and, as a result, the Company adjusted both the liability and capitalized asset. Any negative adjustment in excess of asset retirement cost is reclassified to depreciation, depletion and amortization expense.

Note 12 — Debt Obligations

At December 31, 2014 and 2013, debt obligations consisted of the following:

	December 31, 2014	December 31, 2013
	(in thousands)	
Convertible Notes, 8.5%, due October 2017, net of discount of ($13.9) million at December 31, 2014 and ($18.3) million at December 31, 2013	$ 154,839	$ 125,416
Convertible Notes, 6.5%, due March 2015, net of discount of ($0.4) million at December 31, 2014 and ($4.4) million at December 31, 2013	59,473	81,523
	214,312	206,939
Less: Current maturity of long-term debt	214,312	-
Long-term debt, net	$ -	$ 206,939

The following is a summary of scheduled debt maturities by year (in thousands):

2015	$ 228,600
2016	-
2017	-
2018	-
2019	-
Thereafter	-
Total scheduled debt maturities	$ 228,600

As a result of the Company's decision to not pay the principal and interest on the 2015 Convertible Notes when due on March 1, 2015 and after exercise of a grace period until March 10, 2015, a cross default provision contained on the 2017 Convertible Notes was triggered. In addition, the Company voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code on March 9, 2015, which was also an event of default under both the 2015 Convertible Notes and the 2017 Convertible Notes. Therefore all of the Company's debt and related interest is considered due and callable once the default provisions were triggered and, all debt has been classified as current at December 31, 2014.

Convertible Notes due 2017

During the third quarter of 2013, the Company closed on an offering for an aggregate principal amount of $143.8 million of convertible notes due 2017, which includes the exercise of the underwriter's option to purchase an additional $18.8 million of the 2017 Convertible Notes in addition to the original offering of $125.0 million. The 2017 Convertible Notes are the Company's general senior unsecured obligations and rank equally in right of payment with all of the Company's other existing and future senior unsecured indebtedness and rank senior in the right of payment to all of our existing and future subordinated debt. The 2017 Convertible Notes are subordinate to any secured indebtedness the Company may have to the extent of the value of the assets collateralizing such indebtedness. The 2017 Convertible Notes are not guaranteed by the Company's subsidiaries. In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result, the Company had $168.7 million principal amount of 2017 Convertible Notes outstanding at December 31, 2014.

The interest rate on the 2017 Convertible Notes is 8.50% per year with interest payments due on April 1st and October 1st of each year. The 2017 Convertible Notes mature with repayment of the $168.7 million principal amount (assuming no conversion) on October 1, 2017 (the "2017 Maturity Date").

The conversion rate is 249.5866 shares per $1,000 principal amount (equal to an initial conversion price of approximately $4.0066 per share of common stock). Upon conversion, if conversion is elected by the noteholders, the Company must deliver, at its option, either (1) a number of shares of its common stock determined as set forth in the Indenture dated September 24, 2013 (the "2013 Indenture"), (2) cash, or (3) a combination of cash and shares of its common stock.

Holders may convert their 2017 Convertible Notes at their option at any time prior to the close of business on the second business day immediately preceding the 2017 Maturity Date under any of the following circumstances:

(1) during any fiscal quarter (and only during such fiscal quarter) commencing after October 1, 2013, if the last reported sale price of the Company's common stock is greater than or equal to 130% of the conversion price of the 2017 Convertible Notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter;

(2) prior to July 1, 2017, during the five business-day period after any ten consecutive trading-day period in which the trading price of $1,000 principal amount of the 2017 Convertible Notes for each trading day in the measurement period was less than 97% of the product of the last reported sale price of the Company's common stock and the conversion rate on such trading day; or

(3) upon the occurrence of one of a specified number of corporate transactions.

Holders may also convert the 2017 Convertible Notes at their option at any time beginning on July 1, 2017, and ending at the close of business on the second business day immediately preceding the 2017 Maturity Date or may hold the 2017 Convertible Notes to maturity and be paid their outstanding principal in cash.

The Company may not redeem the 2017 Convertible Notes prior to the 2017 Maturity Date.

The 2013 Indenture for the 2017 Convertible Notes contains customary terms and covenants and events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the 2017 Convertible Notes including (i) an event of default if the Company defaults in the payment when due, after the expiration of any applicable grace period, of indebtedness for money borrowed (including the 2015 Convertible Notes) in the aggregate principal amount then outstanding of $25 million or more, permitting the trustee or the holder of at least 25% in the aggregate principal amount of the outstanding 2017 Convertible Notes to declare the full amount of the principal and interest due thereunder immediately due and payable, and (ii) an event of default if the Company commences a voluntary case under any bankruptcy law, insolvency law or other similar law, whereby the full amount of the principal and interest due thereunder automatically and immediately becomes due and payable. See "—Convertible Notes due 2015" below.

Net proceeds from the sale of the 2017 Convertible Notes, after deducting the discounts and commissions and any offering expenses payable by the Company, were approximately $124.5 million. The 2017 Convertible Notes were issued with a 10% discount or $14.4 million. The underwriter received commissions of approximately $4.3 million in connection with the sale and the Company incurred $0.6 million of direct expenses in connection with the offering. The Company used the net proceeds for general corporate purposes, including funding its exploration and production efforts, other projects and to reduce or refinance its outstanding debt.

The Company accounts for the 2017 Convertible Notes in accordance with ASC Topic 470, "Debt", as it pertains to accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). Under the accounting guidance, convertible debt instruments that may be settled entirely or partially in cash upon conversion are required to be separated into liability and equity components, with the liability component amount determined in a manner that reflects the issuer's non-convertible debt borrowing rate. The value assigned to the liability component is determined by measuring the fair value of a similar liability that does not have an equity conversion feature. The value assigned to the equity component is determined by deducting the fair value of the liability component from the initial proceeds. The excess of the principal amount of the liability component over its carrying amount (the non-cash discount) is amortized to interest cost using the effective interest method over the term of the 2017 Convertible Notes. In addition, transaction costs incurred that directly relate to the issuance of convertible debt instruments must be allocated to the liability and equity components in proportion to the allocation of proceeds and accounted for as debt issuance costs and equity issuance costs, respectively.

The Company estimated its non-convertible borrowing rate at the date of issuance of the 2017 Convertible Notes to be 12.9%. The 12.9% non-convertible borrowing rate represented the borrowing rate of similar companies with the same credit quality as the Company and was obtained through a quote from the underwriter. Using the income method and discounting the principal and interest payments of the 2017 Convertible Notes using the 12.9% non-convertible borrowing rate, the Company estimated the fair value of the $143.8 million 2017 Convertible Notes to be approximately $124.5 million, with the discount being approximately $19.3 million. The discount of $19.3 million includes the 10% discount of $14.4 million and the value of the equity component of $4.9 million. The discount is being amortized as non-cash interest expense over the life of the 2017 Convertible Notes using the effective interest method. In addition, the Company allocated approximately $2.3 million of the $4.9 million of fees and commissions as debt issue costs that are being amortized as non-cash interest expense over the life of the notes using the effective interest method. Approximately $0.1 million of fees and commissions were treated as transaction costs associated with the equity component and the remaining $2.5 million was expensed to other expense under the caption, "Other income (expense)" in the third quarter of 2013.

As a result of the exchange during the second quarter of 2014, the Company estimated its non-convertible borrowing rate at the date of issuance of the $25.0 million 2017 Convertible Notes to be 7.89%. The 7.89% non-convertible borrowing rate represented the borrowing rate of similar companies with the same credit quality as the Company and was obtained through a quote from a financial advisor. Using the income method and discounting the principal and interest payments of the 2017 Convertible Notes with the 7.89% non-convertible borrowing rate, the Company estimated the fair value of the $25.0 million 2017 Convertible Notes to be approximately $25.4 million, with the premium being approximately $0.4 million. The value of the equity component was estimated at $0.5 million. The premium is being amortized as non-cash interest expense over the life of the 2017 Convertible Notes using the effective interest method. In addition, approximately $0.3 million of fees were considered debt issue costs that are being amortized as a non-cash interest expense over the life of the notes using the effective interest method. The Company recognized a loss on this transaction of approximately $0.9 million and this loss was included in the "Loss on extinguishment of debt" in the consolidated statement of operations in the second quarter of 2014. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

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As a result of the Company's decision to not pay the principal and interest on the 2015 Convertible Notes when due on March 1, 2015 and after exercise of a grace period until March 10, 2015, a cross default provision contained on the 2017 Convertible Notes was triggered. In addition, the Company voluntarily filed for reorganization under Chapter 11 of the Bankruptcy Code on March 9, 2015, which was an event of default under both the 2015 Convertible Notes and the 2017 Convertible Notes. Therefore all of the Company's debt and related interest is considered due and callable once the default provisions were triggered and all debt has been classified as current at December 31, 2014. The following table shows the estimated remaining cash payments including interest payments related to the 2017 Convertible Notes, assuming no conversion (in thousands):

Year		
2015	$	175,880
2016		-
2017		-
Total estimated remaining cash payments related to the 2017 Convertible Notes	$	175,880

The Company evaluated the 2013 Indenture for the 2017 Convertible Notes for potential embedded derivatives, noting that the conversion feature and make-whole provisions did not meet the embedded derivative criteria as set forth in ASC Topic 815, "Derivatives and Hedging". Therefore, no additional amounts have been recorded for those items.

As of December 31, 2014, the net amount of $154.8 million includes the $168.7 million of principal reduced by $13.9 million of the remaining unamortized discount. The remaining unamortized discount of $13.9 million may be written off as a result of the Chapter 11 Case. However, if the structure of the debt remains unchanged after the post Chapter 11 proceedings, the unamortized discount will be amortized into interest expense, using the effective interest method, over the remaining life of the 2017 Convertible Notes, which mature in October 2017. The Company is currently in default on its 2015 Convertible Notes. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described in this Item 8 under the caption "—Voluntary Reorganization Under Chapter 11" and "Item 3. Legal Proceedings—Legal Proceedings Related to the Chapter 11 Case." At December 31, 2014, using the conversion rate of 249.5866 shares per $1,000 principal amount of the 2017 Convertible Notes, if the $168.7 million of principal were converted into shares of common stock, the notes would convert into approximately 42.1 million shares of common stock. As of December 31, 2014, there is no excess if-converted value to the holders of the 2017 Convertible Notes as the price of the Company's common stock at December 31, 2014, $0.29 per share, is less than the conversion price.

The annual effective interest rate on the 2017 Convertible Notes, including the amortization of debt issue costs, is approximately 12.5%.

The following table shows the amount of interest expense related to the 2017 Convertible Notes, disregarding capitalized interest considerations, for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31,					
	2014		**2013**		**2012**	
			(in thousands)			
Interest expense related to the contractual interest coupon	$	13,755	$	3,258	$	-
Amortization of debt discount expense		4,005		959		-

Amortization of debt issue costs	610	135	-
Interest expense related to the 2017 Convertible Notes	$ 18,370	$ 4,352	$ -

Convertible Notes due 2015

During the first quarter of 2010, the Company closed on a private offering for an aggregate principal amount of $170.9 million of convertible notes due 2015. The 2015 Convertible Notes are the Company's general senior unsecured obligations and rank equally in right of payment with all of the Company's other existing and future senior unsecured indebtedness. The 2015 Convertible Notes are subordinate to all of the Company's secured indebtedness to the extent of the value of the assets collateralizing such indebtedness. The 2015 Convertible Notes are not guaranteed by the Company's subsidiaries. In September 2013, the Company repurchased $85.0 million of the aggregate principal amount of the $170.9 million of the 2015 Convertible Notes, leaving a principal balance of $85.9 million. In April 2014, $26.0 million of the aggregate principal amount of the 2015 Convertible Notes were exchanged for an additional $25.0 million aggregate principal amount of 2017 Convertible Notes in a private transaction. As a result, the Company had $59.9 million principal amount of 2015 Convertible Notes outstanding at December 31, 2014.

The interest rate on the 2015 Convertible Notes is 6.50% per year with interest payments due on March 1st and September 1st of each year. The 2015 Convertible Notes mature with repayment of the $59.9 million principal amount (assuming no conversion) on March 1, 2015 (the "2015 Maturity Date").

The Company elected not to pay the approximately $62 million in principal and interest due on March 1, 2015 on the 2015 Convertible Notes in order to use a 10-day grace period on principal due and a 30-day grace period on interest due to continue discussions with its debt holders regarding potential terms under which either one or both of the 2015 Convertible Notes and 2017 Convertible Notes could be restructured to provide a capital structure which would allow the Company to continue developing our oil and gas assets, and discussions with potential investors regarding alternative financing solutions. The Company was unable to reach an appropriate solution during the grace period and is in default on payment of the principal amount due under its 2015 Convertible Notes due on March 10, 2015 following its exercise of a 10-day grace period, which also triggered an event of default under its 2017 Convertible Notes, allowing the trustee or the holders of at least 25% in aggregate principal amount under each set of notes to declare the full amounts of principal and interest due. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described in this Item under the caption "—Voluntary Reorganization Under Chapter 11." The filing of the Chapter 11 Case also constituted an event of default that triggered repayment obligations under the 2015 Convertible Notes and the 2017 Convertible Notes. The ability of the holders of the 2015 Convertible Notes and the 2017 Convertible Notes to seek remedies and enforce their rights under the indentures was automatically stayed as a result of the filing of the Chapter 11 Case, and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

The initial conversion rate of 148.3856 shares per $1,000 principal amount (equal to an initial conversion price of approximately $6.74 per share of common stock) was adjusted on February 3, 2011 in accordance with the terms of the Indenture agreement dated February 8, 2010 (the "2010 Indenture").

As a result, the conversion rate and conversion price changed to 169.0082 shares per $1,000 principal amount and $5.9169 per share of common stock, respectively. Upon conversion, if conversion is elected by the noteholders, the Company must deliver, at its option, either (1) a number of shares of its common stock determined as set forth in the 2010 Indenture, (2) cash, or (3) a combination of cash and shares of its common stock.

Holders were permitted to convert their 2015 Convertible Notes at their option at any time prior to the close of business on the second business day immediately preceding the 2015 Maturity Date under any of the following circumstances:

(1) during any fiscal quarter (and only during such fiscal quarter) commencing after March 31, 2010, if the last reported sale price of the Company's common stock is greater than or equal to 130% of the conversion price of the 2015 Convertible Notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter;

(2) prior to January 1, 2015, during the five business-day period after any ten consecutive trading-day period in which the trading price of $1,000 principal amount of the 2015 Convertible Notes for each trading day in the measurement period was less than 97% of the product of the last reported sale price of the Company's common stock and the conversion rate on such trading day;

(3) if the 2015 Convertible Notes have been called for redemption; or

(4) upon the occurrence of one of a specified number of corporate transactions.

Holders were also permitted to convert the 2015 Convertible Notes at their option at any time beginning on February 1, 2015, and ending at the close of business on the second business day immediately preceding the 2015 Maturity Date or may hold the 2015 Convertible Notes to maturity and be paid their outstanding principal in cash.

As of February 3, 2013, the Company was permitted to redeem for cash all or a portion of the 2015 Convertible Notes at a redemption price of 100% of the principal amount of the notes to be redeemed plus any accrued and unpaid interest to, but not including, the redemption date, plus a "make-whole" payment if: (1) for at least 20 trading days in any consecutive 30 trading days ending within 5 trading days immediately before the date the Company mails the redemption notice, the "last reported sale price" of its common stock exceeded 175% of the conversion price in effect on that trading day, and (2) there is no continuing default with respect to the notes that has not been cured or waived on or before the redemption date.

No holders converted their 2015 Convertible Notes and the Company did not redeem any 2015 Convertible Notes prior to the 2015 Maturity Date.

The 2010 Indenture for the 2015 Convertible Notes contains customary terms and covenants and events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the 2015 Convertible Notes.

Net proceeds from the sale of the $170.9 million of 2015 Convertible Notes, after deducting the discounts and commissions and any offering expenses payable by the Company, were approximately $164.9 million. The initial purchaser received commissions of approximately $5.5 million in connection with the sale and the Company incurred approximately $0.6 million of direct expenses in connection with the offering. The Company used the net proceeds for general corporate purposes, including capital expenditures and working capital, reduction or refinancing of debt, and other corporate obligations.

The Company accounts for the 2015 Convertible Notes in accordance with ASC Topic 470, "Debt," as it pertains to accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). Under the accounting guidance, convertible debt instruments that may be settled entirely or partially in cash upon conversion are required to be separated into liability and equity components, with the liability component amount determined in a manner that reflects the issuer's non-convertible debt borrowing rate. The value assigned to the liability component is determined by measuring the fair value of a similar liability that does not have an equity conversion feature. The value assigned to the equity component is determined by deducting the fair value of the liability component from the initial proceeds. The excess of the principal amount of the liability component over its carrying amount (the non-cash discount) is amortized to interest cost using the effective interest method over the term of the 2015 Convertible Notes. In addition, transaction costs incurred that directly relate to the issuance of convertible debt instruments must be allocated to the liability and equity components in proportion to the allocation of proceeds and accounted for as debt issuance costs and equity issuance costs, respectively.

The Company estimated its non-convertible borrowing rate at the date of issuance of the 2015 Convertible Notes to be 12%. The 12% non-convertible borrowing rate represented the borrowing rate of similar companies with the same credit quality as the Company and was obtained through a quote from the initial purchaser. Using the income method and discounting the principal and interest payments of the 2015 Convertible Notes using the 12% non-convertible borrowing rate, the Company estimated the fair value of the $170.9 million 2015 Convertible Notes to be approximately $136.3 million with the discount being approximately $34.6 million. The discount is being amortized as non-cash interest expense over the life of the notes using the effective interest method. In addition, the Company allocated approximately $4.8 million of the $6.1 million of fees and commissions as debt issue costs that are being amortized as non-cash interest expense over the life of the 2015 Convertible Notes using the effective interest method. The remaining $1.3 million of fees and commissions were treated as transaction costs associated with the equity component. The net amount of the equity component was $33.3 million, which included the initial discount of $34.6 million reduced by $1.3 million of direct transaction costs.

In September 2013, the Company repurchased $85.0 million of aggregate principal amount of the 2015 Convertible Notes. As a result of the $85.0 million repurchase during the third quarter of 2013, approximately $12.2 million of the repayment was considered a retirement of debt and the remaining $72.8 million of the repayment were considered an exchange of debt. The $85.0 million of 2015 Convertible Notes were repurchased with an approximate discount of 10%. The Company recognized a gain on the retirement of the debt of approximately $0.2 million and this gain was included in the "Loss on extinguishment of debt" in the consolidated statement of operations in the third quarter of 2013. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

As a result of the exchange during the second quarter of 2014, the $26.0 million of aggregate principal amount of 2015 Convertible Notes exchanged was considered a retirement of debt and deemed a substantial modification of debt. The $26.0 million of 2015 Convertible Notes were exchanged with an approximate discount of 4%. The Company recognized a loss on the retirement of the debt of approximately $0.3 million and this loss was included in the "Loss on extinguishment of debt" in the consolidated statement of operations in the second quarter of 2014. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

The following table shows the estimated remaining cash payments including interest payments related to the 2015 Convertible Notes, assuming no conversion (in thousands):

Year		
2015	$	61,837
Total estimated remaining cash payments related to the 2015 Convertible Notes	$	61,837

The Company evaluated the 2010 Indenture for the 2015 Convertible Notes for potential embedded derivatives, noting that the conversion feature and make-whole provisions did not meet the embedded derivative criteria as set forth in ASC Topic 815, "Derivatives and Hedging." Therefore, no additional amounts have been recorded for those items.

As of December 31, 2014, the net amount of $59.5 million of 2015 Convertible Notes outstanding includes the $59.9 million of principal reduced by $0.4 million of the remaining unamortized discount. The remaining unamortized discount of $0.4 million may be written off as a result of the Chapter 11 Case. However, if the structure of the debt remains unchanged after the post Chapter 11 proceedings, the unamortized discount will be amortized into interest expense, using the effective interest method, over the remaining life of the 2015 Convertible Notes, which mature in March 2015. The

Company is currently in default on its 2015 Convertible Notes. On March 9, 2015, the Debtor filed a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code as described in this Item 8 under the caption "—Voluntary Reorganization Under Chapter 11" and "Item 3. Legal Proceedings—Legal Proceedings Related to the Chapter 11 Case." At December 31, 2014, using the conversion rate of 169.0082 shares per $1,000 principal amount of the 2015 Convertible Notes, if the $59.9 million of principal were converted into shares of common stock, the notes would convert into approximately 10.1 million shares of common stock. As of December 31, 2014, there is no excess if-converted value to the holders of the 2015 Convertible Notes as the price of the Company's common stock at December 31, 2014, $0.29 per share, is less than the conversion price.

For the year ended December 31, 2014, the annual effective interest rate on the 2015 Convertible Notes, including the amortization of debt issue costs, was approximately 12.0%.

The following table shows the amount of interest expense related to the 2015 Convertible Notes, disregarding capitalized interest considerations, for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31,		
	2014	**2013**	**2012**
		(in thousands)	
Interest expense related to the contractual interest coupon	$ 4,386	$ 9,622	$ 11,111
Amortization of debt discount expense	2,896	6,051	6,698
Amortization of debt issue costs	762	977	956
Interest expense related to the 2015 Convertible Notes	$ 8,044	$ 16,650	$ 18,765

$75.0 Million Secured Debt Facility

On July 6, 2011, the Company and its subsidiaries entered into a credit agreement with Credit Suisse and other parties (collectively the "lenders"), whereby the lenders agreed to provide a $75.0 million secured debt facility in two loan tranches to the Company's subsidiary, BPZ E&P. The full amount available under the $75.0 million secured debt facility was drawn down by the Company on July 7, 2011. In April 2012, the Company and the lenders amended the terms of the $75.0 million secured debt facility and in May 2012, the Company prepaid $40.0 million of the principal balance of the $75.0 million secured debt facility. In May 2013, the Company prepaid the remaining principal balance of the $75.0 million secured debt facility.

Proceeds from the $75.0 million secured debt facility were utilized to pay certain fees and expenses under the $75.0 million secured debt facility, to fund a debt service reserve account under the $75.0 million secured debt facility, to reimburse certain affiliates of BPZ E&P for up to $14.0 million of capital and exploratory expenditures incurred by them in connection with the development of Block Z-1 and up to $6.0 million of capital and exploratory expenditures incurred by them in connection with the development in Block XIX in northwest Peru, and to finance BPZ E&P's capital and exploratory expenditures in connection with the development of Block Z-1.

As a result of the prepayment of the remaining principal balance during the second quarter of 2013, the Company incurred $2.4 million of fees and a prepayment premium. The $2.4 million in fees and prepayment premium were recognized as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations in the second quarter of 2013. Approximately $1.4 million representing the remaining unamortized debt issue costs on the loan was expensed as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations when the Company prepaid the remaining principal in the second quarter of 2013. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

As a result of the prepayment and amendment during the second quarter of 2012, the Company incurred $5.8 million of fees and prepayment premium and $1.1 million of debt issue costs. The $5.8 million in fees and prepayment premium were recognized as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations, of which 25% was paid at the time of the amendment and prepayment and 25% was paid at the time of each of the next three quarterly interest payment dates ending in January 2013. Approximately $1.5 million of the remaining $2.8 million of unamortized debt issue costs associated with the initial loan was expensed as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations when the Company prepaid $40.0 million of principal. For further information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

The $75.0 million secured debt facility, as amended, provided for an ongoing fee through July 2014 payable by BPZ E&P to the lenders of the Performance Based Arranger Fee whose amount is determined by the change in the price of Brent crude oil at inception of the loans and the price at each principal repayment date in accordance with the original loan principal repayment dates, subject to a 12% ceiling of the original principal amount borrowed. For further information on the Performance Based Arranger Fee, see Note-13, "Derivative Financial Instruments" and Note-15, "Fair Value Measurements and Disclosures."

$40.0 Million Secured Debt Facility

In January 2011, the Company, through its subsidiaries, completed a credit agreement with Credit Suisse whereby Credit Suisse provided a $40.0 million secured debt facility to the Company's power generation subsidiary, Empresa Eléctrica Nueva Esperanza S.R.L. On April 27, 2012, the Company and its subsidiaries, Empresa Eléctrica Nueva Esperanza S.R.L. and BPZ E&P, entered into a fourth amendment to the $40.0 million secured debt facility with Credit Suisse. In May 2013, the Company amended and restated the $40.0 million secured debt facility (which had been repaid by scheduled principal repayments to $25.5 million) by increasing the facility size and borrowing an additional $14.5 million. In September 2013, the Company prepaid the remaining principal balance of the $40.0 million secured debt facility.

In 2013, the $14.5 million of proceeds from the amended and restated $40.0 million secured debt facility was utilized to meet the Company's 2013 capital, exploration and development work programs as well as for general corporate purposes. In 2011, the proceeds from the $40.0 million secured debt facility were utilized to meet the Company's 2011 capital, exploration and development work programs, and to reduce other debt obligations.

As a result of the prepayment of the remaining principal balance during the third quarter of 2013, the Company incurred $2.0 million in fees and prepayment premium. The $2.0 million in fees and prepayment premium were recognized as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations. Approximately $1.7 million representing the remaining unamortized debt issue costs loan was expensed as a "Loss on extinguishment of debt" in the Consolidated Statement of Operations when the Company prepaid the remaining principal. For information on debt issue costs see Note-7, "Prepaid and Other Current Assets and Other Non-Current Assets."

In May 2013, as a result of amending and restating the $40.0 million secured debt facility (which had been repaid by scheduled principal repayments to $25.5 million) to increase the facility size and borrowing an additional $14.5 million, the Company added $1.8 million of debt issue costs. The $1.8 million of new debt issue costs was combined with the remaining $0.6 million of unamortized debt issue costs and was originally planned to be amortized over the remaining term, ending in January 2015, using the effective interest method. For further information on debt issue costs, see Note-7, “Prepaid and Other Current Assets and Other Non-Current Assets.”

The $40.0 million secured debt facility, as amended, provided for ongoing fees through July 2013 payable to Credit Suisse including a Performance Based Arranger Fee whose amount is determined by the change in the price of Brent crude oil at inception of the loan and the price at each principal repayment date in accordance with the original loan principal repayment dates, subject to a 18% ceiling of the original principal amount borrowed. For further information on the Performance Based Arranger Fee, see Note-13, “Derivative Financial Instruments” and Note-15, “Fair Value Measurements and Disclosures.”

Pacific Rubiales Obligations

On April 27, 2012, the Company and Pacific Rubiales executed a SPA where the Company formed an unincorporated joint venture with Pacific Rubiales to explore and develop the offshore Block Z-1 located in Peru. Pursuant to the SPA, Pacific Rubiales agreed to pay $150.0 million for a 49% participating interest, including reserves, in Block Z-1 and agreed to fund $185.0 million of the Company’s share of capital and exploratory expenditures in Block Z-1 from the effective date of the SPA, January 1, 2012 (together, the “Pacific Rubiales Loans”). Until the required approvals were obtained, Pacific Rubiales provided the Company $65.0 million and other funds as loans to continue to fund the Company’s Block Z-1 capital and exploratory activities. These amounts were reflected as long-term debt prior to closing the transaction.

On December 14, 2012, Perupetro approved the terms of the amendment to the Block Z-1 License Contract to recognize the sale of a 49% participating interest, in offshore Block Z-1 to Pacific Rubiales. The Company and Pacific Rubiales waived and modified certain contract conditions in order to close the transaction. On December 30, 2012, the Peruvian Government signed the Supreme Decree for the execution of the amendment to the Block Z-1 License Contract.

At closing, Pacific Rubiales exchanged certain loans along with an additional $85.0 million, plus any other amounts due to the Company or from the Company under the SPA, for the interests and assets obtained from the Company under the SPA and under the Block Z-1 License Contract.

At December 31, 2014 and December 31, 2013, the Company reflected $22.5 million and $23.9 million, respectively, as other current liabilities and zero and $16.8 million, respectively, as other non-current liabilities for exploratory expenditures related to Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount is being settled by the Company and Pacific Rubiales under the terms of the SPA with the cash payments under the liability of $14.4 million occurring in 2014.

Capital Leases

In June 2007, the Company entered into a capital lease agreement, with an option to purchase two vessels, the Namoku and the Nu’uanu, to assist in the development of the Corvina oil field. The capital lease assets were recorded at $6.2 million, which represented the present value of the minimum lease payments, or the aggregate fair market value of the assets.

In May 2009, the Company entered into an amendment of its lease agreement for the two vessels under charter, the Namoku and the Nu’uanu. Under the terms of the amended lease agreement, the charter, originally set to expire in November 2009, was extended for five years commencing on May 1, 2009. During the first 18 months of the amended lease term, the daily charter rate for the use of both vessels was fixed. Commencing in November 2010, the daily charter rate for the use of both vessels was based on a tiered structure with the daily rate dependent upon the amount of the previous month's average daily per barrel price of West Texas Intermediate Crude Oil ("WTI"), as indicated on the New York Mercantile Exchange. Any amount paid by the Company after November 2010 over the initial daily rate as a result of the escalated tiered structure based on the price of WTI was considered contingent rental payments. The amount of the contingent lease payments paid in 2012 was $0.6 million. The amended lease agreement contained a $3.0 million purchase option after the third year of the lease, a $2.0 million purchase option after the fourth year of the lease and a mandatory $1.0 million purchase obligation by the Company after the fifth year of the lease. The Company accounted for the amended lease agreement in accordance with ASC Topic 840, "Leases." Under the guidance, the lease agreement continued to be accounted for as a capital lease and the imputed interest rate necessary to reduce the net minimum lease payments to present value over the lease term is 34.9%. In May 2012, the Company exercised the third year purchase option for $3.0 million and purchased the marine vessels, the Namoku and the Nu'uanu, at which point titles to the vessels were transferred to the Company.

At December 31, 2014 and December 31, 2013, the Company had no amounts outstanding under capital leases.

Interest Expense

The following table is a summary of interest expense for the year ended December 31, 2014, 2013 and 2012, respectively:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Interest expense	$ 27,920	$ 26,016	$ 31,719
Capitalized interest expense	(9,250)	(9,858)	(15,604)
Interest expense, net	$ 18,670	$ 16,158	$ 16,115

Note 13 — Derivative Financial Instruments

Objective and Strategies for Using Derivative Instruments:

In connection with the $40.0 million secured debt facility through July 2013 and the $75.0 million secured debt facility through July 2014, the Company and Credit Suisse agreed that a portion of the arranger fee would be based on the performance for oil prices and be payable at each of the principal repayment dates. The fee is calculated by multiplying the principal payment amount by the change in oil prices from the loan origination date and the oil price at each principal repayment date. Additionally, the fee is capped at 18% of the $40.0 million secured debt facility and 12% of the $75.0 million secured debt facility. The Performance Based Arranger Fee is being accounted for as an embedded financing derivative under ASC Topic 815, "Derivatives and Hedging" and accordingly, is being recorded at fair value with any changes in value reflected as a gain or loss on derivatives in the accompanying Consolidated Statements of Operations. The following table sets forth a reconciliation of the changes in fair value of the Company's derivative financial instrument for the years ended December 31:

Derivative Financial Instruments Not Designated as Hedging Instruments

	2014	2013	2012
		(in thousands)	
Beginning fair value of derivatives	$ 30	$ 2,984	$ 2,046
(Gain) loss on derivatives	(2)	(242)	2,610
Cash settlements paid	(28)	(2,712)	(1,672)
Ending fair value of derivatives	$ -	$ 30	$ 2,984

See Note-15, "Fair Value Measurements and Disclosures" for a discussion of methods and assumptions used to estimate the fair values of the Company's derivative instruments.

Note 14 — Stockholders' Equity

The Company has 25,000,000 shares of preferred stock, no par value and 250,000,000 shares of common stock, no par value, authorized for issuance.

Potentially Dilutive Securities

Basic earnings (loss) per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings (loss) per share of common stock may include the effect of the Company's shares issuable under a convertible debt agreements, outstanding stock options, shares of restricted stock or performance stock units, except in periods in which there is a net loss. The following table summarizes the calculation of basic and diluted earnings (loss) per share:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands, except per share data)		
Net loss	$ (107,906)	$ (57,711)	$ (39,089)
Shares:			
Basic weighted average common shares outstanding	116,311	115,943	115,631
Incremental shares from assumed conversion of dilutive share based awards	-	-	-
Diluted weighted average common shares outstanding	116,311	115,943	115,631
Excluded share based awards (1) (2)	7,707	7,413	6,723
Excluded 2017 convertible debt shares (1)	42,108	35,878	-
Excluded 2015 convertible debt shares (1)	10,122	14,516	28,890

Basic net loss per share	$	(0.93)	$	(0.50)	$	(0.34)
Diluted net loss per share	$	(0.93)	$	(0.50)	$	(0.34)

(1) Inclusion of the shares for these awards would have had an antidilutive effect.
(2) Inclusion of the performance share units for these awards would have had an antidilutive effect. The actual number of performance share units earned may range from 0% to 200%.

The following table summarizes stock-based compensation costs recognized under ASC Topic 718, "Stock Compensation," for the year ended December 31, 2014, 2013, and 2012, respectively, and is included in "General and administrative expense" on the Consolidated Statements of Operations:

	For the Year Ended December 31,		
	2014	**2013**	**2012**
		(in thousands)	
Employee stock-based compensation costs	$ 2,426	$ 2,189	$ 2,283
Director stock-based compensation costs	730	606	532
Employee stock purchase plan costs	7	11	26
Total stock-based compensation costs	$ 3,163	$ 2,806	$ 2,841

Stock Options, Restricted Stock and Performance Share Plans

The Company has in effect the 2007 Long-Term Incentive Compensation Plan, as amended in 2010 and 2014 to increase the number of shares available (the "2007 LTIP"), and the 2007 Directors' Compensation Incentive Plan (the "Directors' Plan"). The 2007 LTIP and Directors' Plan provide for awards of options, stock appreciation rights, restricted stock, restricted stock units, performance awards, other stock-based awards and cash-based awards to any of the Company's officers, employees, consultants and the employees of certain of the Company's affiliates as well as non-employee directors. The number of shares authorized under the amended 2007 LTIP and Directors' Plan is 12.0 million and 4.0 million, respectively, which includes an additional 4.0 million shares related to the 2007 LTIP and 1.5 million shares related to the Directors' Plan approved by the Company's shareholders on June 20, 2014. As of December 31, 2014, approximately 4.5 million shares remain available for future grants under the 2007 LTIP and 1.8 million shares remain available for future grants under the Directors' Plan.

Restricted Stock Awards and Performance Stock Units

Restricted Stock

At December 31, 2014, there were 2,203,322 shares of restricted stock awards outstanding to officers, directors and employees all of which generally vest with the passage of time on the second or third anniversary of the date of grant. Restricted stock is subject to certain restrictions on ownership and transferability when granted. The fair value of restricted stock awards is based on the market price of the Common Stock on the date of grant. Compensation cost for such awards is recognized ratably over the vesting or service period, net of forfeitures; however, compensation cost related to performance shares will not be recorded or will be reversed if the Company does not believe it is probable that such performance criteria will be met or if the service provider (employee or otherwise) fails to meet such criteria.

A summary of the Company's restricted stock award activity for the year ended December 31, 2014 and related information is presented below:

	Number of Restricted Shares	Weighted—Average Fair Value Per Share
Outstanding at the beginning of the year	1,490,555	$ 3.00
Granted	1,109,230	2.18
Vested	(297,787)	4.00
Forfeited or expired	(98,676)	2.49
Outstanding at the end of the year	2,203,322	$ 2.47

The weighted average grant-date fair value of restricted stock awards granted for the year ended December 31, 2013 and 2012 was $2.72 and $3.29, respectively. The fair value of restricted stock awards that vested during the year ended December 31, 2014, 2013 and 2012 was $1.2 million, $1.4 million, and $1.2 million, respectively. As of December 31, 2014, there was $1.9 million of total unrecognized compensation cost related to non-vested restricted stock awards, which is expected to be recognized over a weighted-average period of 1.4 years.

Performance Stock Units

On February 20, 2014, the Company's Board of Directors awarded 225,695 shares of performance stock units, which are referred to by the Company as Relative Performance Stock Units, to officers under the Company's 2007 LTIP. Shares of the Company's common stock will be issued following the vesting of the Relative Performance Stock Units determined based on the level of achievement of the performance measure at the end of the performance period (from January 1, 2014 through December 31, 2016). The actual number of shares of Company common stock to be issued at payment is measured on a three-year cumulative stock price basis relative to a selected peer group and can range from a minimum of 0% of the number of shares of Company common stock granted to a maximum of 200% of the number of shares of Company common stock granted.

Compensation expense associated with these Relative Performance Stock Units is based on the grant date fair value of a single Relative Performance Stock Unit as determined using a Monte Carlo simulation model. As the Company intends to settle these Relative Performance Stock Units with shares of the Company's common stock at the end of the performance period, the Relative Performance Stock Unit awards are accounted for as equity awards and the expense is calculated on the grant date and amortized over the life of the Relative Performance Stock Unit awards. The grant date fair value per share of the Relative Performance Stock Unit award granted was $2.12.

As of December 31, 2014, there was $0.3 million of unrecognized compensation cost related to the Relative Performance Stock Units.

A summary of the Company’s Relative Performance Stock Units activity for the year ended December 31, 2014 is presented below:

	Number of Relative Performance Stock Units	Fair Value Per Share
Outstanding at the beginning of the year	-	$ -
Granted	225,695	2.12
Vested	-	-
Forfeited or expired	-	-
Outstanding at the end of the year	225,695	$ 2.12

In addition, on February 20, 2014, the Company’s Board of Directors awarded 225,694 shares of performance stock units, which are referred to by the Company as Absolute Performance Stock Units, to officers under the Company’s 2007 LTIP. Shares of the Company's common stock will be issued following the vesting of the Absolute Performance Stock Units determined based on the level of achievement of the performance measure at the end of the performance period (from January 1, 2014 through December 31, 2016). The actual number of shares of the Company common stock to be issued at payment is measured on a three-year cumulative stock price basis relative to pre-established stock price goals and can range from a minimum of 0% of the number of shares of Company common stock granted to a maximum of 200% of the number of shares of Company common stock granted.

Compensation expense associated with these Absolute Performance Stock Units is based on the grant date fair value of a single Absolute Performance Stock Unit as determined using a Monte Carlo simulation model. As the Company intends to settle these Absolute Performance Stock Units with shares of the Company’s common stock at the end of the performance period, the Absolute Performance Stock Unit awards are accounted for as equity awards and the expense is calculated on the grant date and amortized over the life of the Absolute Performance Stock Unit awards. The grant date fair value per share of the Absolute Performance Stock Unit award granted was $0.80.

As of December 31, 2014, there was $0.1 million of unrecognized compensation cost related to the Absolute Performance Stock Units.

A summary of the Company’s Absolute Performance Stock Units activity for the year ended December 31, 2014 is presented below:

	Number of Absolute Performance Stock Units	Fair Value Per Share
Outstanding at the beginning of the year	-	$ -
Granted	225,694	0.80
Vested	-	-
Forfeited or expired	-	-
Outstanding at the end of the year	225,694	$ 0.80

The following table presents the assumptions used to estimate the grant date fair value of the performance stock units granted during the year ended December 31:

	2014	2013	2012
Expected life (years) (a)	2.9	-	-
Risk-free interest rate (c)	0.67%	-	-
Volatility (b)	64.6%	-	-
Dividend yield (d)	-	-	-

(a) The expected life is the period between the grant date and the last day of the performance period.
(b) The volatility is based on the historical volatility of our stock for a period approximating the expected life.
(c) The risk-free interest rate is based on the observed U.S. Treasury yield curve in effect at the time the performance stock units were granted.
(d) The dividend yield is based on the fact the Company does not anticipate paying any dividends.

Stock Options

Incentive and non-qualified stock options issued to directors, officers, employees and consultants are typically granted at the fair market value on the date of grant. The Company's stock options generally vest in equal annual installments over a two to three year period and expire ten years from the date of grant.

The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option pricing model. The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options, which have no vesting restrictions and are fully transferable and negotiable in a free trading market. This model does not consider the employment, transfer or vesting restrictions that are inherent in the Company's stock options.

Use of an option valuation model includes highly subjective assumptions based on long-term predictions, including the expected stock price volatility and expected option term of each stock option grant.

The following table presents the weighted-average assumptions used in the option pricing model for options granted during the year ended December 31:

	2014	2013	2012
Expected life (years) (a)	-	5.1	4.2
Risk-free interest rate (c)	-	0.8%	0.8%
Volatility (b)	-	82.5%	85.8%
Dividend yield (d)	-	-	-
Weighted-average fair value per share at grant date	$ -	$ 1.78	$ 2.48

(a) The expected life was derived based on a weighting between (a) the Company's historical exercise and forfeiture activity and (b) the average midpoint between vesting and the contractual term and (c) from the analysis of other companies of a similar size and operational life cycle.
(b) The volatility is based on the historical volatility of our stock for a period approximating the expected life.
(c) The risk-free interest rate is based on the observed U.S. Treasury yield curve in effect at the time the options were granted.
(d) The dividend yield is based on the fact the Company does not anticipate paying any dividends.

BPZ RESOURCES, INC. AND SUBSIDIARIES
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A summary of the Company's stock option activity for the year ended December 31, 2014 and related information is presented below:

	Number of Options	Weighted—Average Exercise Price Per Option	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at the beginning of the year	5,922,709	$ 7.70		
Granted	-	-		
Exercised	(99,248)	1.30		
Forfeited or expired	(319,922)	7.57		
Outstanding at the end of the year	5,503,539	$ 7.83	4.47	$ -
Exercisable at the end of the year	4,997,760	$ 8.31	4.11	$ -

The weighted average grant date fair value of stock options granted for the year ended December 31, 2013 and 2012 was $1.78 and $2.48, respectively. As of December 31, 2014, there was $0.5 million of unrecognized compensation cost related to non-vested stock options that is expected to be recognized over a weighted average period of 1.0 years. The total intrinsic value of stock options (defined as the amount by which the market price of the Common Stock on the date of exercise exceeds the exercise price of the stock option) exercised during the year ended December 31, 2014, 2013, and 2012 was $0.1 million, none and none, respectively. Cash received from stock option exercises for the year ended December 31, 2014, 2013 and 2012 was $0.1 million, none and none, respectively.

The following table summarizes information about stock options outstanding as of December 31, 2014:

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Options	Weighted-Average Remaining Contractual Life (In years)	Weighted Exercise Price	Number of Options	Weighted-Average Exercise Price Per Option
Below to $ 4.23	1,698,127	5.8	$ 3.32	1,192,348	$ 3.45
$ 4.24 to $ 6.35	1,372,231	4.5	5.08	1,372,231	5.08
$ 6.36 to $ 8.47	614,181	4.9	6.45	614,181	6.45
$ 8.48 to $ 10.58	182,500	3.0	10.21	182,500	10.21

$ 10.59 to $ 25.53	1,636,500	3.1		15.06	1,636,500		15.06
Total	5,503,539	4.5	$	7.83	4,997,760	$	8.31

Employee Stock Purchase Plan

The employee stock purchase plan ("ESPP"), which was approved by the shareholders on June 24, 2011, provides eligible employees the opportunity to acquire shares of BPZ Resources, Inc. common stock at a discount, through payroll deductions. Employees are allowed to purchase up to 2,500 shares in any one offering period (not longer than twenty-seven months), within Internal Revenue Service ("IRS") limitations and plan rules. The offering period means each period of time which common stock is offered to participants. Unless otherwise determined by the Compensation Committee, a new offering period shall commence on the first day of each calendar quarter. Generally, the purchase price for stock acquired under the plan is the lower of 85% (subject to Compensation Committee adjustment) of the fair market value of the common stock on the grant date or the fair market value of the common stock on the investment date. Under this plan, 2,000,000 common shares were reserved for issuance and purchase by eligible employees. Activity under this plan began in the first quarter of 2012. At December 31, 2014, 1,912,346 shares were available for issuance. On January 2, 2015, 6,222 shares were issued to employees at a price of $0.25 per share.

The fair value of all ESPP grants is estimated using the Black-Scholes pricing model. The table below represents the valuation assumptions used to value the ESPP grants and the weighted average fair value for the year ended December 31:

	2014	**2013**	**2012**
Expected life (months)	3	3	3
Risk-free interest rate	0.04%	0.06%	0.08%
Volatility	24.4%	25.4%	35.3%
Dividend yield	-	-	-
Weighted-average fair value of grants	$ 0.33	$ 0.38	$ 0.58
Shares purchased during year	21,183	26,460	40,011
Average number of participants per quarter	6	5	12

Note 15 — Fair Value Measurements and Disclosures

The Company records certain of its assets and liabilities on the balance sheet at fair value. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). A three-level valuation hierarchy has been established to allow readers to understand the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

- Level 1 — Fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities.

- Level 2 — Fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.

- Level 3 — Fair value measurements which use unobservable inputs.

The following describes the valuation methodologies the Company uses for its fair value measurements.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Cash and Cash Equivalents

Cash and cash equivalents include all cash balances and any highly liquid investments with an original maturity of 90 days or less. The carrying amount approximates fair value because of the short maturity of these instruments.

Restricted Cash

Restricted cash includes all cash balances which are associated with the Company's long-term assets, short-term debt and long-term debt. The carrying amount approximates fair value because the nature of the restricted cash balance is the same as cash. The fair value of restricted cash is measured using Level 1 inputs within the three-level valuation hierarchy.

Derivative Financial Instruments

The Company's derivative financial instruments consist of variable financing arranger fee payments that are dependent on the change in oil prices from the loan origination date of the Company's $40.0 million secured debt facility (through July 2013), the $75.0 million secured debt facility (through July 2014) and the oil price on each repayment date. The Company estimated the fair value of these payments based on published forward commodity price curves at each financial reporting date. The discount rate used to discount the associated cash flows was based on the Company's credit-adjusted risk-free rate. Accordingly, these derivatives are considered to be a Level 2 measurement on the fair value hierarchy. For further information regarding the Company's derivatives, see Note-13, "Derivative Financial Instruments."

Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

		Fair Value Measurements Using:		
	Balance Sheet	Quoted Prices in Active Markets	Significant Other Observable Inputs	Significant Unobservable Inputs

	Location	(Level 1)	(Level 2)	(Level 3)
			(in thousands)	
December 31, 2014				
Financial Liabilities				
Derivative Financial Instruments				
	Current Liabilities	$ -	$ -	$ -
	Non-current Liabilities	-	-	-
	Total	$ -	$ -	$ -
December 31, 2013				
Financial Liabilities				
Derivative Financial Instruments				
	Current Liabilities	$ -	$ 30	$ -
	Non-current Liabilities	-	-	-
	Total	$ -	$ 30	$ -

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of long-lived assets, at fair value on a non-recurring basis. The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition. None of the Company's non-financial assets and liabilities were impaired during the year ended December 31, 2013.

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3) (a)	Before-Tax Loss
		(in thousands)		
For the Year Ended December 31, 2014				
Long-lived assets held for use - Power plant and related equipment	$ -	$ -	$ 32,801	$ 58,000

(a) Represents fair value at the time of impairment.

The long-lived assets held for use are impaired to their fair values. The fair value was measured using an probability weighted average income approach and considered project specific assumptions for future project operating revenues and costs and expected plant construction and operations, anticipated proceeds in the event a sale of the assets, including a liquidation scenario, and the estimated value to be received in the event the assets were included in a joint venture operation.

Additional Fair Value Disclosures

Debt with Fixed Interest Rates

The fair value information regarding the Company's fixed rate debt is as follows:

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)		(in thousands)	
Convertible Notes, 8.5%, due October 2017, net of discount of ($13.9) million at December 31, 2014 and ($18.3) million at December 31, 2013 (1)	$ 154,839	$ 57,361	$ 125,416	$ 130,094
Convertible Notes, 6.5%, due March 2015, net of discount of ($0.4) million at December 31, 2014 and ($4.4) million at December 31, 2013 (2)	59,473	20,662	81,523	79,663

(1) The Company estimated the fair value of the 2017 Convertible Notes to be approximately $57.4 million and $130.1 million at December 31, 2014 and December 31, 2013, respectively, based on observe market prices for the same or similar types of debt issues. The fair value of the 2017 Convertible Notes is considered to be a Level 1 measurement on the fair value hierarchy.

(2) The Company estimated the fair value of the 2015 Convertible Notes to be approximately $20.7 million and $79.7 million at December 31, 2014 and December 31, 2013, respectively, based on observe market prices for the same or similar types of debt issues. The fair value of the 2015 Convertible Notes is considered to be a Level 1 measurement on the fair value hierarchy.

Note 16 — Affiliate and Related Party Transactions

For the year ended December 31, 2014, 2013 and 2012, the Company had not entered into any transactions with affiliates or related parties.

Note 17 — Revenue

The oil produced is delivered by vessel to the refinery owned by the Peruvian national oil company, Petroleos del Peru - PETROPERU S.A. ("Petroperu"), in Talara, located approximately 70 miles south of the platforms. Produced oil is kept in production inventory until inventory quantities are at a sufficient level to make a delivery to the refinery in Talara. Although all of the Company's oil sales are to Petroperu, it believes the loss of Petroperu as its sole customer would not materially impact the Company's business because it could readily find other purchasers for the Company's oil production both in Peru and throughout the world.

The Company's revenues are reported net of royalties owed to the government of Peru. Royalties are assessed by Perupetro, as stipulated in the Block Z-1 License Contract based on production.

The following table shows the amount of royalty costs of approximately 5% of gross revenues for the year ended December 31:

Year Ended December 31,		
2014	2013	2012

	(in thousands)		
Royalty costs	$ 4,674	$ 2,707	$ 6,605

Note 18 — Standby Costs

For the year ended December 31, 2014, the Company had no standby rig costs.

For the year ended December 31, 2013, the Company incurred $4.3 million in standby rig costs.

During 2013 the Company had the Petrex-10 rig partially or fully on standby for approximately three months and two rigs, the Petrex-28 rig and Petrex-21 rig, partially or fully on standby for approximately five months.

For the year ended December 31, 2012, the Company incurred $5.3 million in standby rig costs.

During 2012, the Company had the Petrex-18 rig, which was previously leased to another operator in 2011, on standby through July 31, 2012. The Company's contract on this rig was amended and the contract was suspended from August 1, 2012 through April 30, 2013. The Company had the Petrex-28 rig on standby, from September 2012 through December 2012, as the Company expected to use this rig in drilling operations on the CX-15 platform. Additionally in 2012, the Company had a workover rig, the Petrex-10, on standby for two months to allow for seismic acquisition activities where the workover rig was operating.

Note 19 — Other Operating Expense

For the year ended December 31, 2014, the Company reported $4.3 million of charges in the Consolidated Statements of Operations as "Other operating expense." The Company expensed these previously capitalized amounts related to marine operations, a drilling site location and certain equipment and associated capitalized interest that it does not see a future economic benefit in these costs.

For the year December 31, 2013, the Company reported $4.4 million of charges in the Consolidated Statements of Operations as "Other operating expense." The Company expensed these costs related to historical pre-development drilling studies for drilling locations and platform technologies and associated capitalized interest as it believes that these locations and technologies may change and it does not see a future value for these studies.

For the year ended December 31, 2012, the Company reported $2.3 million of abandonment charges in the Consolidated Statements of Operations as "Other operating expense." The Company accrued $2.3 million of abandonment costs related to a platform in the Piedra Redonda field in Block Z-1, as it is obligated to ensure the offshore platform does not cause a threat to navigation in the area or marine wildlife. The $2.3 million charge is in addition to the Piedra Redonda platform abandonment costs previously recorded in the third quarter of 2010.

Note 20 — Income Taxes

The source of net loss before income tax expense (benefit) for the year ended December 31 is as follows (in thousands):

	2014	2013	2012
United States	$ (47,899)	$ (31,163)	$ (6,465)
Foreign	(29,033)	(32,323)	(48,238)
Loss before income taxes	$ (76,932)	$ (63,486)	$ (54,703)

The income tax expense (benefit) for the year ended December 31 consists of the following (in thousands):

	2014	2013	2012
Current Taxes			
Federal	$ -	$ 668	$ -
Foreign	1,431	2,595	13,551
Total Current	1,431	3,263	13,551
Deferred Taxes			
Federal	-	-	-
Foreign	29,543	(9,038)	(29,165)
Total Deferred	29,543	(9,038)	(29,165)
Total income tax expense (benefit)	$ 30,974	$ (5,775)	$ (15,614)

The income tax expense (benefit) for the year ended December 31 differs from the amount computed by applying the U.S. statutory federal income tax rate for the applicable year to consolidated net loss before income taxes as follows (in thousands):

	2014	2013	2012
Federal statutory income tax rate	$ (26,157)	$ (21,585)	$ (18,599)
Increases (decreases) resulting from:			
Peruvian income tax - rate difference less than 34% statutory	6,694	3,341	7,791
Asset impairment	7,767	-	-
Permanent book/tax differences	1,530	262	(621)
Non-deductible intercompany expenses and other	-	(198)	2,763
Effect of asset sale with retained oil intangible tax attribute	-	-	(15,111)
Effect of cumulative profit sharing adjustment	-	-	(895)
Effect of foreign exchange rate	(126)	(1,462)	(1,678)

Current year foreign withholding tax	1,433	1,690	1,699
Change in valuation allowance	39,833	11,509	9,037
Uncertain tax positions	-	668	-
Total income tax expense (benefit)	$ 30,974	$ (5,775)	$ (15,614)

A summary of the components of deferred tax assets, deferred tax liabilities and other taxes deferred at December 31 are presented below (in thousands):

	2014	**2013**
Deferred Tax:		
Asset:		
Net Operating Loss	$ 80,170	$ 77,588
Deferred Compensation	5,330	4,704
Asset Basis Difference	9,858	9,253
Exploration Expense	15,624	15,836
Depletion	-	-
Asset Retirement Obligation	809	809
Overhead Allocation to Foreign Locations	19,601	10,207
Other	1,342	2,078
Liability:		
Depreciation	(6,429)	(6,272)
Other	-	-
Net Deferred Tax Asset	126,305	114,203
Less Valuation Allowance	(92,308)	(50,601)
Deferred tax asset	$ 33,997	$ 63,602

At December 31, 2014, the Company has recognized a gross deferred tax asset related to net operating loss carryforwards of $80.2 million before application of the valuation allowances. Net deferred tax assets in the foregoing table include the deferred consequences of the future reversal of Peruvian deferred tax assets and liabilities on the impact of the Peruvian employee profit share plan tax of zero in 2014 and $7.0 million in 2013. For the year ended December 31, 2014, the Company established a full valuation allowance related to the $6.4 million deferred tax asset applicable to the Peruvian employee profit sharing plan as the more likely than not criteria as to whether the future benefits would be realized was not met.

At December 31, 2014, the Company had recognized a gross deferred tax asset related to net operating loss carryforwards attributable to the United States of $62.7 million, before application of the valuation allowances. As of December 31, 2014, the Company had a valuation allowance for the full amount of the domestic deferred tax asset of $50.1 million, resulting from the income tax benefit generated from net losses, as it believes, based on the weight of available evidence, that it is more likely than not that the deferred tax asset will not be realized prior to the expiration of net operating loss carryforwards in various amounts through 2034. Furthermore, because the Company has no operations within the U.S. taxing jurisdiction, it is likely that sufficient generation of revenue to offset the Company's deferred tax asset is remote.

In 2011, the Company amended its 2009 U.S. Federal Tax return to elect to deduct its previously benefited foreign income tax credits. This resulted in an increase to the Company's net operating loss carryforward and the elimination of the foreign income tax credit carryforward previously accrued as a deferred tax asset. Since the Company maintained a full valuation allowance against the net operating loss carryforward and the foreign tax credit carryforward deferred tax assets, the election to deduct the foreign tax credit resulted in no impact to overall tax expense.

At December 31, 2014, the Company had recognized a gross deferred tax asset related to net operating loss carryforwards attributable to foreign jurisdictions of $17.5 million, before application of the valuation allowances, attributable to foreign net operating losses, which begin to expire in 2015. The Company is subject to Peruvian income tax on its earnings at a statutory rate, as defined in the Block Z-1 License Contract, of 22%. The Company assessed its ability to realize the deferred tax asset generated in Peru. The Company considered whether it is more likely than not that some portion or all of the deferred tax asset will not be realized. The ultimate realization of the deferred tax asset is dependent upon the generation of future taxable income in Peru during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income, the availability of certain prudent and feasible income tax planning opportunities and projections for future taxable income over the periods in which the deferred tax assets are deductible, along with the transition into the commercial phase under the Block Z-1 License Contract, the Company does not believe it is more likely than not that it will realize all of the deductible differences at December 31, 2014. Therefore, the Company has recorded a $42.2 million valuation allowance composed of the following:

(1) A $1.9 million valuation allowance on certain foreign deferred tax assets related to overhead allocations and exploration activities on Blocks XIX, XXII and XXIII, as it believes it may not receiv the full benefit of these deductions,
(2) A $15.4 million valuation allowance on the 2011 through 2013 BPZ E&P net operating losses that expire starting in 2015 as the Company believes it may not receive the full benefit of thes deductions,
(3) A $6.7 million valuation allowance on certain BPZ E&P overhead expenses that the Company believes it may not receive the full benefit of these deductions, and
(4) A $11.8 million valuation allowance on the deferred tax assets of its foreign subsidiary engaging in the development of the gas-to-power project, as the Company considered it more likely than no that a portion or all of the subsidiary's deferred tax assets will not be realized. Further, the Company will place a valuation allowance on future deferred tax assets of that same foreign subsidiar until the Company believes it is more likely than not the deferred tax assets will be realized.

As a result, the Company recognized a net deferred tax asset of $34.0 million related to its foreign operations as of December 31, 2014.

The Company recognized a total tax provision for the year ended December 31, 2014 of approximately $31.0 million. No provision for U.S. federal and state income taxes has been made for the difference in the book and tax basis of the Company's investment in foreign subsidiaries as such amounts are considered permanently invested. Distribution of earnings, as dividends or otherwise, from such investments could result in U.S. federal taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable in various foreign countries. Due to the Company's significant net operating loss carryforward position the Company has not recognized any excess tax benefit related to its stock compensation plans. ASC Topic 718 prohibits the recognition of such benefits until the related compensation deduction reduces the current tax liability.

A reconciliation of the beginning and ending amount of unrecognized tax benefits at December 31 is as follows (in thousands):

	2014		2013		2012	
Balance January 1	$	668	$	-	$	-
Additions related to tax positions taken in the current year		-		-		-
Additions related to tax positions of prior years		47		668		-
Reductions related to tax positions of prior years		-		-		-
Reductions related to settlements with taxing authorities		-		-		-
Reductions related to lapses in statute of limitations		-		-		-
Balance December 31	$	715	$	668	$	-

The December 31, 2014 balance of unrecognized tax benefits includes $0.7 million that, if recognized, would impact the Corporation's effective income tax rate. Over the next 12 months, the Company does not anticipate any reduction in the balance. The Company had accrued interest and penalties related to unrecognized tax benefits of 47,000, $46,000 and zero as of December 31, 2014, 2013 and 2012, respectively. Estimated interest and penalties related to potential underpayment on unrecognized tax benefits, if any, are classified as a component of income tax expense in the Consolidated Statement of Operations.

Note 21 — Business Segment Information

The Company determines and discloses its segments in accordance with ASC Topic 280, "Segment Reporting" ("ASC Topic 280"), which uses a "management" approach for determining segments. The management approach designates the internal organization that is used by management for making operating decisions and assessing performance as the source of the Company's reportable segments. ASC Topic 280 also requires disclosures about products or services, geographic areas, and major customers. The Company's management reporting structure provided for only one segment for the year ended December 31, 2014, 2013 and 2012. Accordingly, no separate segment information is presented. In addition, the Company operates only in Peru and has only one customer for its oil production, Petroperu. The majority of the Company's long-lived assets are located in Peru. Management does not consider its investment in Ecuador as a separate business segment.

Note 22 — Commitments and Contingencies

Ecuadorian Hydrocarbon Law

In July 2010, the Company was notified of changes to the Ecuadorian hydrocarbon law that included provisions that will allow the Ecuadorian government to nationalize oil fields if a private operator does not agree to contractual changes mandated by the new hydrocarbon laws. The Consortium, of which the Company is a participant, successfully negotiated a service contract during the fourth quarter of 2010; accordingly, the Company does not believe there is a significant risk of nationalization of its interest in the Santa Elena field. For further information see Note-9, "Investment in Ecuador Property." However, the Company does not believe any such impact on its Ecuadorian investment will have a material impact on the Company's overall financial position.

Santa Elena Field

In 2013, in order to extend the term of the contract from 2016 to 2029, the Consortium, which includes the Company and three other partners, agreed to additional work commitments to increase production in the Santa Elena field. The Company's total share of this commitment over the remaining life of the contract is $4.8 million (the Company's 10% non-operating net profits interest) which amount is due for the remainder of 2014 to 2028. This commitment is expected to be funded by cash on hand, cash generated from new production, or loans of the Consortium. If the Consortium does not have sufficient cash on hand, the Company may elect to make a cash contribution to the Consortium for its 10% share of the commitment. If the Company elects not to make its 10% share contribution of the commitment, it would lose its rights in the Consortium and the contract for the Santa Elena field.

In the fourth quarter of 2014, the Consortium incurred a loan for the additional work commitments to increase production in the Santa Elena field. The Consortium loan is to be paid with cash generated from the production of the Santa Elena Field. The Company's total share of this loan would be $1.0 million (our 10% non-operating net profits interest) which amounts are due quarterly through the fourth quarter of 2017. If the Consortium does not have sufficient cash on hand, the Company would make a cash contribution to the Consortium for its 10% share of this loan.

Profit Sharing

The Constitution of Peru and Legislative Decree Nos. 677 and 892 give employees working in private companies engaged in activities generating income as defined by the Income Tax Law the right to share in the company's profits. According to Article 3 of the United Nations International Standard Industrial Classification, BPZ E&P's tax category is classified under the "mining companies" section, which sets the profit sharing rate at 8%. However, in Peru, the Hydrocarbon Law states, and the Supreme Court ruled, that hydrocarbons are not related to mining activities. Hydrocarbons are included under "Companies Performing Other Activities," thus Oil and Gas Companies pay profit sharing at a rate of 5%. The 5% of income is determined by calculating a percentage of the Company's Peruvian subsidiaries' annual total revenues subject to income tax less the expenses required to produce revenue or maintain the source of revenues. The benefit granted by the law to employees is calculated on the basis of "income subject to taxation" per the Peruvian tax code, and not based on income (loss) before incomes taxes as reported under GAAP. For the year ended December 31, 2014, December 31, 2013 and December 31, 2012, respectively, profit sharing expense was not material to the Company as the Company's Peruvian subsidiaries did not have a material amount of "income subject to taxation" per the Peruvian tax code as a result of declaring commercial production in the Corvina field, which allowed certain exploration and development costs to be deductible in 2014, 2013 and 2012 that were not deductible in previous years. The Company is subject to profit sharing expense in any year its Peruvian subsidiaries are profitable according to the Peruvian tax laws.

Gas-to-Power Project Financing

The gas-to-power project entails the planned installation of approximately 10 miles of gas pipeline from the CX-11 platform to shore, the construction of gas processing facilities and the building of an approximately 135 megawatt ("MW") simple-cycle electric generating plant. The power plant site is located adjacent to an existing substation and power transmission lines. The existing substation and transmission lines are owned and operated by third parties.

The Company currently estimates the gas-to-power project will cost approximately $153.5 million, excluding capitalized interest, working capital and 18% value-added tax which will be recovered via future revenue billings. The $153.5 million includes $133.5 million for the estimated cost of the power plant and $20.0 million for the natural gas pipeline. While the Company has held initial discussions with several potential joint venture partners for the gas-to-power project in an attempt to secure additional financing and other resources for the project, the Company has not entered into any definitive agreements with a potential partner. In the event the Company is able to identify and reach an agreement with a potential joint venture partner, it may only retain a minority position in the project, or the power generation facility may be wholly owned by a third party. However, the Company along with its Block Z-1 partner, Pacific Rubiales, expects to retain the responsibility for the construction of the pipeline as well as retain ownership of the pipeline. The Company has obtained certain permits and is in the process of obtaining additional permits to proceed with the project.

Note 23 — Legal Proceedings

Legal Proceedings Related to the Chapter 11 Case

On March 9, 2015, BPZ Resources, Inc. filed a voluntary petition in the United States Bankruptcy Court for the Southern District of Texas Victoria Division (the "Bankruptcy Court") seeking relief under the provisions of Chapter 11 of Title 11 of the United States Bankruptcy Code (the "Bankruptcy Code"). The Chapter 11 case is being administered under the caption *In re BPZ Resources, Inc.*, Case No. 15-60016 (the "Chapter 11 Case"). The Company will continue to operate its business as "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. As a result of the filing, attempts to collect, secure, or enforce remedies with respect to pre-petition claims against the Company are subject to the automatic stay provisions of section 362 of the Bankruptcy Code. None of the Company's direct or indirect subsidiaries has filed for reorganization under Chapter 11 and none are expected to file for reorganization or protection from creditors under any insolvency or similar law in the U.S. or elsewhere. The Chapter 11 Case is discussed in greater detail in Note-2 "Liquidity and Capital Resources" to our Consolidated Financial Statements.

Other Legal Proceedings

From time to time the Company may become a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, the Company is not currently a party to any proceeding that it believes could have a potentially material adverse effect on its financial condition, results of operations or cash flows.

Additionally, the Company is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

Note 24 — Operating Leases and Purchase Obligations

The Company is committed under various operating leases. Rent expense incurred for the year ended December 31, 2014, 2013 and 2012 was approximately $3.9 million, $2.9 million and $1.2 million, respectively. See Note-18, "Standby Costs," for drilling rig equipment expense included in the Consolidated Statements of Operations.

Minimum non-cancelable lease, purchase commitments and current liabilities as of December 31, 2014 are as follows (in thousands):

2015	$	23,889
2016		1,095
2017		1,049
2018		1,071
2019		724

Thereafter		11,265
Total minimum lease, purchase commitments and current liabilities	$	39,093

Includes operating leases for the Company's executive office in Houston, Texas (expires in 2016), the Company's branch offices in Peru (expires in 2016 and 2019) and warehouses in Peru (expires in 2038), respectively.

Includes current liabilities ($22.5 million) related to exploratory expenditures for Block Z-1 under funding by Pacific Rubiales of the exploratory expenditures in Block Z-1 incurred in 2012. This amount will be settled by the Company and Pacific Rubiales under terms of the SPA.

Note 25 — Subsequent Events

Voluntary Reorganization Under Chapter 11

See Note-2, "Liquidity and Capital Resources," for information on the Company's Voluntary Reorganization under Chapter 11.

Note 26 — Quarterly Results of Operations (Unaudited)

	Three Months Ended							
	March 31,		**June 30,**		**September 30, (a)**		**December 31, (b)**	
	(in thousands except per share data)							
2014								
Total net revenue	$	20,976	$	24,255	$	20,350	$	18,316
Operating income (loss)		2,123		4,363		(40,084)		(24,077)
Other expense		(3,743)		(4,787)		(2,580)		(8,147)
Net loss	$	(3,570)	$	(2,549)	$	(45,292)	$	(56,495)
Basic net loss per share	$	(0.03)	$	(0.02)	$	(0.39)	$	(0.49)
Diluted net loss per share	$	(0.03)	$	(0.02)	$	(0.39)	$	(0.49)
Basic weighted average common shares outstanding		116,042		116,342		116,399		116,453
Diluted weighted average common shares outstanding		116,042		116,342		116,399		116,453

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands except per share data)			
2013				
Total net revenue	$ 13,312	$ 12,815	$ 12,529	$ 12,073
Operating loss	(7,241)	(12,664)	(10,853)	(5,656)
Other expense	(5,213)	(7,353)	(10,239)	(4,267)
Net loss	$ (12,784)	$ (19,640)	$ (15,321)	$ (9,966)
Basic net loss per share	$ (0.11)	$ (0.17)	$ (0.13)	$ (0.09)
Diluted net loss per share	$ (0.11)	$ (0.17)	$ (0.13)	$ (0.09)
Basic weighted average common shares outstanding	115,788	115,935	116,009	116,035
Diluted weighted average common shares outstanding	115,788	115,935	116,009	116,035

(a) Includes asset impairments of $41.0 million and an increase to the deferred income tax valuation allowance of $9.9 million.

(b) Includes asset impairments of $17.0 million and an increase to the deferred income tax valuation allowance of $32.3 million.

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

Supplemental Oil and Gas Disclosures (Unaudited)

Oil and Natural Gas Producing Activities

The following disclosures for the Company are made in accordance with ASC Topic 932, “Extractive Activities –Oil and Gas” and SEC rules for oil and gas reporting disclosures. Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas ultimately recovered.

In December 2012, the Company completed the sale of 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

Reserves

Proved reserves represent estimated quantities of crude oil and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed 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 tests in the area and in the same reservoir.

Our relevant management controls over proved reserve attribution, estimation and evaluation include:

- controls over and processes for the collection and processing of all pertinent operating data and documents needed by our independent reservoir engineers to estimate our proved reserves;
- engagement of well qualified and independent reservoir engineers for review of our operating data and documents and preparation of reserve reports annually in accordance with all SEC reserv estimation guidelines;
- review by our senior reservoir engineer and his staff of the independent reservoir engineers' reserves reports for completion and accuracy; and
- oversight and review by our Technical Committee, made up of independent members of the Board of Directors, who review the propriety of our methodology and procedures for determining the o and gas reserves as well as the reserves estimates resulting from such methodology and procedures. The Technical Committee may also review the qualifications, independence and performance o our independent reserve engineers.

An unweighted average of the first-day-of-the month price based upon the prior 12-month period is used for future sales of natural gas, crude oil and natural gas liquids. Future operating costs, production taxes and capital costs are based on current costs as of each year-end, with no escalation. Numerous interpretations and assumptions are made in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of the proved oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risks.

Proved Undeveloped Reserves ("PUD" or "PUDs")

As of December 31, 2014, 9.4 MMBbls of PUDs were reported, a decrease of 3.5 MMBbls from December 2013. The following table shows changes in the PUDs for 2014:

	MBbls
PUDs at January 1, 2014	12,915
Revisions of previous estimates	(1,572)
Purchases of minerals in place	-
Extensions, discoveries and other additions	2,157
Sales of reserves in place	-
Conversion to proved developed reserves	(4,139)
PUDs at December 31, 2014	9,361

In 2014, the Company had negative revisions to PUDs of 1.4 MMBbls from previous estimates due to performance revisions for the Corvina field.

In 2014, the Company converted 4.1 MMBbls, or 31.8% of total year-end 2013 PUDs to developed status. As of December 31, 2014, the Company had a total quantity of 19 PUD locations contributing 9.4 MMBbls to its 2014 proved oil reserves. Of the total 19 PUDs, 13 PUDs are associated with the Corvina field and 6 PUD locations are associated with the Albacora field. Costs incurred to advance the development of PUDs associated with Block Z-1 in 2014 were approximately $127.2 million, of which $124.6 million was funded by our partner in Block Z-1, Pacific Rubiales. Costs incurred to advance the development of PUDs associated with Block Z-1 in 2013 were approximately $70.6 million which was reimbursed by the Company’s partner in Block Z-1, Pacific Rubiales. Costs incurred to advance the development of PUDs in 2012 associated with Block Z-1 were approximately $60.2 million of which $56.8 million was reimbursed by the Company’s partner in Block Z-1, Pacific Rubiales. Costs reimbursed by Pacific Rubiales include the Pacific Rubiales 49% participating interest. As a result of unexpected governmental permitting delays, facilities limitations on the CX-11 offshore platform and contractual and construction issues related to the CX-15 offshore platform, at December 31, 2013, certain PUD locations in Corvina field were included as proved oil reserves that were scheduled to be drilled five years after initial disclosure. In 2014, we completed nine development wells in the Corvina and Albacora fields and converted 31.8% of our 2013 PUD MMBbls to proved developed reserves. The drilling rig is in place and we plan to continue to drill to convert the PUDS. For 2015 we have wells that will be drilled five years after the initial disclosure, the timing of the development of these wells has been changed in conjunction with a shared development plan with our partner in Block Z-1. This shared development plan is not the same drilling plan we initially adopted when we were the sole operator of the Corvina and Albacora fields. The current development plan would result in all PUDs being drilled by 2017.

In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth the capitalized costs relating to the Company’s natural gas and crude oil producing activities at December 31, 2014 and 2013:

	2014	2013

	(in thousands)			
Proved properties	$	188,555	$	193,023
Unproved properties		29,488		11,734
Total		218,043		204,757
Less: Accumulated depreciation, depletion and amortization		(107,804)		(93,488)
Net capitalized cost		110,239		111,269
Company's share of cost method investees' costs of property acquisition, exploration and development (1)	$	-	$	-

(1) The Company purchased the Investment in Ecuador Property in 2004.

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company's oil and natural gas activities for the year ended December 31, 2014 and 2013 (in thousands):

		Total
Year Ended December 31, 2014:		
Acquisition costs of properties		
Proved	$	-
Unproved		-
Total acquisition costs		-
Exploration costs (1)		23,795
Development costs (2)		6,136
Total	$	29,931
Company's share of cost method investees' costs of property acquisition, exploration and development (3)	$	-
Year Ended December 31, 2013:		
Acquisition costs of properties		
Proved	$	-

Unproved		-
Total acquisition costs		-
Exploration costs (1)		5,514
Development costs (2)		503
Total	$	6,017
Company’s share of cost method investees’ costs of property acquisition, exploration and development (3)	$	-

(1) Pacific Rubiales provided funding for exploratory costs for Block Z-1 of $34.7 million for the year ended December 31, 2014 and $4.4 million for the year ended December 31, 2013.

(2) In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1. Pacifi Rubiales provided funding for development capital expenditures for Block Z-1 of $139.4 million and $79.1 million for the year ended December 31, 2014 and December 31, 2013, respectively.

(3) The Company purchased the Investment in Ecuador Property in 2004.

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

Results of Operations for Oil and Natural Gas Producing Activities

The results of operations for oil and natural gas producing activities, excluding general and administrative expenses and interest expense, are as follows for the periods indicated:

	Year Ended December 31,		
	2014	**2013**	**2012**
		(in thousands)	
Oil revenue, net	$ 83,464	$ 50,585	$ 122,708
Geological, geophysical and engineering expense	3,773	2,184	43,787
Lease operating expense	28,571	24,893	52,458
Depletion and amortization expense	14,837	17,984	31,453
Income (loss) before income taxes	36,283	5,524	(4,990)
Income tax provision (benefit)	7,982	1,215	(1,097)

Results of continuing operations	$ 28,301	$ 4,309	$ (3,893)
Company's share of cost method investees' results of operations for producing activities(1)	$ 250	$ 250	$ 250

(1) Investment in Ecuador Property.

In January 2013, the Company made a change in its method of estimating the depreciation of producing equipment. The Company changed to the unit-of-production method from a straight-line five-year life method of calculating depreciation because it more accurately matches the costs of production equipment to the Company's oil production.

In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

Net Proved Reserve Summary

The following table sets forth the Company's net proved developed and undeveloped reserves at December 31, 2014, 2013 and 2012, and the changes in the net proved reserves for each of the three years. All of the Company's proved reserves are located in Peru. The Company's net profit interest in the Santa Elena property is located in Ecuador and is based on a service contract.

	Natural gas (MMcf)(4)	Natural gas liquids and crude oil (MBbls)(1)	(MBbls) equivalents(2)
Net proved reserves at December 31, 2011	-	34,702	34,702
Revisions of previous estimates (6)	-	(681)	(681)
Purchases of minerals in place	-	-	-
Extensions, discoveries and other additions (5)	-	-	-
Sales of reserves in place (7)	-	(16,410)	(16,410)
Production (8)	-	(1,185)	(1,185)
Other	-	-	-
Net proved reserves at December 31, 2012	-	16,426	16,426
Revisions of previous estimates (6)	-	(132)	(132)
Purchases of minerals in place	-	-	-
Extensions, discoveries and other additions (5)	-	344	344

Sales of reserves in place	-	-	-
Production (8)	-	(514)	(514)
Other	-	-	-
Net proved reserves at December 31, 2013	-	16,124	16,124
Revisions of previous estimates (6)	-	(4,488)	(4,488)
Purchases of minerals in place	-	-	-
Extensions, discoveries and other additions (5)	-	2,871	2,871
Sales of reserves in place	-	-	-
Production (8)	-	(941)	(941)
Other	-	-	-
Net proved reserves at December 31, 2014	-	13,566	13,566
Company's proportional interest in reserves of investees accounted for by the cost method—December 31, 2014 (3)	-	23	23

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

	Natural gas (MMcf)(4)	Natural gas liquids and crude oil (MBbls)(1)	(MBbls) equivalents(2)
Proved Developed Reserves as of:			
December 31, 2010	-	12,231	12,231
December 31, 2011	-	6,546	6,546
December 31, 2012	-	2,125	2,125
December 31, 2013	-	3,209	3,209
December 31, 2014	-	4,205	4,205

Proved Undeveloped Reserves as of:			
December 31, 2010	-	26,645	26,645
December 31, 2011	-	28,156	28,156
December 31, 2012	-	14,301	14,301
December 31, 2013	-	12,915	12,915
December 31, 2014	-	9,361	9,361

(1) Includes crude oil, condensate and natural gas liquids.

(2) Natural gas volumes have been converted to equivalent natural gas liquids and crude oil volumes using a conversion factor of six thousand cubic feet of natural gas to one barrel of natural gas liquids and crude oil.

(3) Based on a preliminary report provided by the operator of the Santa Elena Property.

(4) The Company does not currently have the financial capacity or commitments for a development program of this magnitude for its gas reserves. Accordingly, the Company has not included amoun of natural gas reserves in its SEC filings. At such time as the Company obtains sufficient financial commitments to proceed with the full development of the gas-to-power project and all other condition necessary to record proved gas reserves are met, the Company expects to record SEC proved gas reserves as permitted under SEC rules and disclose such reserves in future SEC filings.

(5) In 2012, there were no changes to the extensions, discoveries and other additions. The 2013 extensions, discoveries and other additions of 0.3 MMBbls were due to an additional well drilled in th Albacora field. The 2014 extensions, discoveries and other additions of 2.9 MMBbls were due to additional wells drilled in the Albacora field.

(6) The 2012 reserve analysis prepared by NSAI included negative revisions due to performance of 0.7 MMBbls. The negative revisions were due to workovers pending on the 14D and 15D wells at th Corvina CX-11 platform, as well as removal of the Albacora A12F well from the proved category given its required conversion to a gas injection well. The 2013 reserve analysis as prepared by NSA included negative revisions of approximately 120 MBbls due to performance and negative revisions due to price of approximately 12 MBbls. The 2014 reserve analysis as prepared by NSAI include negative revisions of approximately 4,399 MBbls due to performance and negative revisions due to price of approximately 89 MBbls. The 2012, 2013 and 2014 reserve reports as prepared by NSA used a $108.10 per barrel price, a $105.32 per barrel price and a $99.65 per barrel price, respectively.

(7) During 2012, sales of reserves in place of 16.4 MMBbls relates to the Company's sale of a 49% participating interest in Block Z-1.

(8) The 2012 oil production of 1,185 MBbls includes 908 MBbls from the Corvina field and 277 MBbls from the Albacora field. The 2013 oil production of 514 MBbls includes 395 MBbls from th Corvina field and 119 MBbls from the Albacora field. The 2014 oil production of 941 MBbls includes 512 MBbls from the Corvina field and 429 MBbls from the Albacora field.

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by U.S. GAAP and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum reservoir engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's oil and natural gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. Such estimated cash flows have been prepared assuming that the Company's license contract will allow production for the possible 40-year term for both oil and gas. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available under current laws and which relate to oil and natural gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's crude oil reserves for the year ended December 31, 2014, 2013 and 2012 (in thousands):

December 31, 2014		
Future cash inflows (3)	$	1,351,874
Future production costs		(502,100)
Future development costs		(128,128)
Future income tax expenses		(121,589)
Future net cash flows		600,057
Discount to present value at 10% annual rate		(183,259)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$	416,798
Company's share of cost method investees' standardized measure of discounted future net cash flows (1) (2)	$	1,182
December 31, 2013		
Future cash inflows (3)	$	1,698,127
Future production costs		(345,709)

Future development costs		(103,304)
Future income tax expenses		(196,372)
Future net cash flows		1,052,742
Discount to present value at 10% annual rate		(374,692)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$	678,050
Company's share of cost method investees' standardized measure of discounted future net cash flows (1) (2)	$	1,520
December 31, 2012		
Future cash inflows (3)	$	1,775,659
Future production costs		(235,932)
Future development costs		(81,413)
Future income tax expenses		(261,259)
Future net cash flows		1,197,055
Discount to present value at 10% annual rate		(305,742)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$	891,313
Company's share of cost method investees' standardized measure of discounted future net cash flows (1) (2)	$	7,575

(1) Investment in Ecuador Property
(2) Based on management's estimate.
(3) The per barrel price used in determining future cash inflows for the year ended December 31, 2014, 2013 and 2012 were $99.65, $105.32 and $108.10, respectively.

BPZ RESOURCES, INC AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)
YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

The following table sets forth the principal changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil reserves. The information is presented for the year ended December 31, 2014, 2013 and 2012 as follows:

	Year Ended December 31,		
	2014	**2013**	**2012**
		(in thousands)	
Standardized measure of discounted future net cash flows, beginnning of the year	$ 678,050	$ 891,313	$ 1,533,733

Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(54,894)	(25,691)	(70,250)
Change in estimated future development costs	(17,504)	(10,702)	56,152
Net changes in prices and production costs (1)	(206,227)	(140,647)	(14,265)
Extensions, discoveries, additions and improved recovery, net of related costs	137,145	13,936	-
Development costs incurred	29,784	102	867
Revisions of previous quantity estimates (2)	(220,362)	(271,583)	(37,362)
Accretion of discount	79,162	108,665	190,766
Net change in income taxes	32,055	81,764	178,588
Sales of reserves in place (3)	-	-	(972,568)
Changes in timing and other	(40,411)	30,893	25,652
Standardized measure of discounted future net cash flows, end of the year	$ 416,798	$ 678,050	$ 891,313

(1) For the year ended December 31, 2014, the decrease in net changes in prices and production costs is due to overall lower revenues and higher costs on all reserves that are not extensions or revision

(2) For the year ended December 31, 2014, the decrease in revisions to previous quantity estimates is due to negative performance of wells drilled in 2014 causing a negative revision to those we reserves and the associated PUDs in the areas drilled.

For the year ended December 31, 2013, the decrease in revisions to previous quantity estimates is due to a change in the Corvina Field flow profile methodology used by our reserve engineers tha extends the time period over which the reserves are produced.

(3) In December 2012, the Company completed the sale of a 49% participating interest in the Block Z-1 License Contract. The Company now owns a 51% participating interest in Block Z-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

We performed an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer have concluded that as of December 31, 2014 our disclosure controls and procedures, as defined in Rule 13a-15(e), are effective to ensure that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Commission’s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures.

(b) Changes in Internal Control Over Financial Reporting

There was no change in the Company's internal control over financial reporting during the quarter ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

(c) Management's Annual Report on Internal Control over Financial Reporting

Management of the Company, including our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls are designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States, as well as to safeguard assets from unauthorized use or disposition.

Management conducted an evaluation of the effectiveness of our internal controls over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. We did not identify any material weaknesses in our internal controls as a result of this evaluation. Based on this evaluation, management has concluded that our internal controls over financial reporting were effective as of December 31, 2014.

BDO USA, LLP, the independent registered public accounting firm who also audited our consolidated financial statements, has issued an attestation report on our internal control over financial reporting as of December 31, 2014, which is set forth below under "Attestation Report."

(d) Attestation Report

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
BPZ Resources, Inc. and Subsidiaries
Houston, Texas

We have audited BPZ Resources, Inc.'s internal control over financial reporting 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 COSO criteria). BPZ Resources, Inc.'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 "Item 9A, Management's Annual Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, BPZ Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of BPZ Resources, Inc. as of December 31, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014, and our report dated March 16, 2015 expressed an unqualified opinion thereon and included an explanatory paragraph regarding the Company's ability to continue as a going concern.

/s/ BDO USA, LLP

Houston, TX
March 16, 2015

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the SEC within 120 days after the end of our fiscal year covered by this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the SEC within 120 days after the end of our fiscal year covered by this Annual Report on Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference from our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the SEC within 120 days after the end of our fiscal year covered by this Annual Report on Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the SEC within 120 days after the end of our fiscal year covered by this Annual Report on Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference from our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the SEC within 120 days after the end of our fiscal year covered by this Annual Report on Form 10-K.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. Financial Statements.

2. Financial Statements Schedules and supplementary information required to be submitted:

None.

3. Exhibits

A list of the exhibits filed or furnished with this report on Form 10-K (or incorporated by reference to exhibits previously filed or furnished by us) is provided in the Index of Exhibits of this report. Those exhibits incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Otherwise, the exhibits are filed herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry that are used in this report.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest:

- Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- Same environment of deposition;
- Similar geological structure; and
- Same drive mechanism.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent determined using the ratio of approximately six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Bopd. Barrels of oil per day.

Boepd. Barrels of oil equivalent per day.

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

Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

- Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

- Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

- Provide improved recovery systems.

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

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of approximately six Mcf of natural gas to one Bbl of crude oil or other hydrocarbon.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids.

Oil. Crude oil, condensate and natural gas liquids.

Production costs. (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Productive well. A well that is found to be capable of producing hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved. The SEC provides a complete definition of proved developed reserves in Rule 4-10(a)(3) of Regulation S-X.

Proved reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and cost as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

Proved undeveloped reserves. Proved oil and gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved 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 tests in the area and in the same reservoir. The SEC provides a complete definition of proved undeveloped reserves in Rule 4-10(a)(4) of Regulation S-X.

Recompletion. The completion for production of an existing well bore in another formation from that which the well has been previously completed.

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

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

Workover. A remedial operation on a completed well to restore, maintain or improve the well's production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 16, 2015.

BPZ Resources, Inc.

By: */s/ Manuel Pablo Zúñiga-Pflücker*
Manuel Pablo Zúñiga-Pflücker
President & Chief Executive Officer

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

/s/ MANUEL PABLO ZÚÑIGA-PFLÜCKER

/s/ RICHARD S. MENNITI

Manuel Pablo Zúñiga-Pflücker
President, Chief Executive Officer and Director
March 16, 2015

Richard S. Menniti
Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)
March 16, 2015

/s/ JAMES B. TAYLOR
James B. Taylor
Director and Chairman of the Board
March 16, 2015

/s/ JOHN J. LENDRUM, III
John J. Lendrum, III
Director
March 16, 2015

/s/ STEPHEN C. BEASLEY
Stephen C. Beasley
Director
March 16, 2015

/s/ ROBERT L. SOVINE
Robert L. Sovine
Director
March 16, 2015

/s/ STEPHEN R. BRAND
Stephen R. Brand
Director
March 16, 2015

/s/ RICHARD J. SPIES
Richard J. Spies
Director
March 16, 2015

/s/ JERELYN EAGAN
Jerelyn Eagan
Director
March 16, 2015

/s/ DENNIS G. STRAUCH
Dennis G. Strauch
Director
March 16, 2015

INDEX OF EXHIBITS

2.1		Plan of Conversion for BPZ Energy, Inc. (incorporated by reference to Exhibit 2.1 to the Company’s Form 8-K filed on August 24, 2007).
3.1		Certificate of Formation of BPZ Resources, Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Form 8-K filed on August 24, 2007).
3.2		Bylaws of BPZ Resources, Inc. (incorporated by reference to Exhibit 3.2 to the Company’s Form 8-K filed on August 17, 2007).

3.3		First Amendment to the Bylaws of BPZ Resources, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Form 8-K filed on March 7, 2011).
4.1		Indenture for 6.5% Convertible Senior Notes due 2015 by and among BPZ Resources Inc. and Wells Fargo Bank National Association, as trustee, dated February 8, 2010 (incorporated by reference to exhibit 4.1 to the Company's Form 8-K filed on February 9, 2010).
4.2		Form of 6.5% Convertible Senior Note due 2015 (included in Exhibit 4.1).
4.3		Underwriting Agreement by and among BPZ Resources, Inc. and Raymond James and Associates, Inc. dated September 19, 2013 (incorporated by reference to Exhibit 1.1 to the Company's Form 8-K filed on September 25, 2013).
4.4		Indenture for 8.5% Convertible Senior Notes due 2017 by and among BPZ Resources Inc. and Wells Fargo Bank, National Association, as trustee, dated September 24, 2013 (incorporated by reference to Exhibit 4.1 to the Company's Form 8-K filed on September 25, 2013).
4.5		Form of 8.5% Convertible Senior Note due 2017 (form included in the Indenture being incorporated by reference herein as Exhibit 4.4).
10.1*		BPZ Energy, Inc. 2005 Long-Term Incentive Compensation Plan (incorporated by reference to Exhibit 4.1 to the Company's Form S-8 filed on July 5, 2005 (SEC File No. 333- 126388)).
10.2*		BPZ Energy, Inc. 2007 Long-Term Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed on August 24, 2007).
10.3*		BPZ Energy, Inc. 2007 Directors Compensation Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Form 8-K filed on August 24, 2007).
10.4		Merger Agreement between Navidec, Inc. and BPZ Energy, Inc. dated July 8, 2004 (incorporated by reference to Exhibit 10.1 from the Company's Form 8-K filed on July 13, 2004).
10.5		Closing Agreement between Navidec, Inc. and BPZ, Inc. dated September 8, 2004 (incorporated by reference to Exhibit 10.1 from the Company's Form 8-K filed on September 14, 2004)
10.6		License Contract from the Government of Peru for Block Z-1 dated November 30, 2001 (incorporated by reference to Exhibit 10.5 to the Company's Form SB-2 filed on February 14, 2005 (SEC File No. 333-122816)).
10.7		Amendment to License Contract from the Government of Peru for Block Z-1 dated February 3, 2005 (incorporated by reference to Exhibit 10.5 of the Company's Annual Report on Form 10-KSB for the year ended December 31, 2004 filed on April 15, 2005).

10.8		License Contract from the Government of Peru for Block XIX dated December 12, 2003 (incorporated by reference to Exhibit 10.6 to the Company's Form SB-2 filed on February 14, 2005 (SEC File No. 333-122816)).
10.9		License Contract from the Government of Peru for Block XXII dated November 21, 2007 (incorporated by reference to Exhibit 10.9 to the Company's Form 10-K filed on March 14, 2008).
10.10		License Contract from the Government of Peru for Block XXIII dated November 21, 2007 (incorporated by reference to Exhibit 10.10 to the Company's Form 10-K filed on March 14, 2008).
10.11		Contract No. 001-2009-Mextipetroperu - Supply of 17,000,000 Barrels of Crude Oil for Talara Refinery dated January 8, 2009, by and among BPZ Exploración & Producción S.R.L., and Petroleos del Perú-PETROPERU S.A.(incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed on January 14, 2009).
10.12		Contract for Sale of Equipment and Services dated September 26, 2008 (incorporated by reference to Exhibit 10.11 to BPZ Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 filed on November 10, 2008).
10.13		Amendment dated January 23, 2009 to Contract for Sale of Equipment and Services dated September 26, 2008 by and among GE Packaged Power, Inc. GE International, Inc. Sucursal De Peru and Empresa Eléctrica Nueva Esperanza, SRL (incorporated by reference to Exhibit 10.2 to the Company's Form 8-K filed on January 29, 2009).
10.14		Subscription Agreement by and among BPZ Resources, Inc. and International Finance Corporation dated December 18, 2006 (incorporated by reference to exhibit 10.1 to the Company's Form 8-K filed on December 22, 2006).
10.15		Letter Agreement by and between the Consortium of GE Packaged Power, Inc. and GE International Inc. Sucursal de Peru (collectively, "Seller") and Empresa Electrica Nueva Esperanza S.R.L. ("Buyer") dated as of November 20, 2009 (incorporated by reference to exhibit 10.3 to the Company's Form 8-K filed on November 27, 2009).
10.16		US $40,000,000 Credit Agreement by and among Empresa Electrica Nueva Esperanza S.R.L., as Borrower, and BPZ Resources, Inc., and BPZ Exploración & Producción S.R.L., as Guarantors and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent, and Credit Suisse International, as Arranger, dated as of January 27, 2011 (incorporated by reference to exhibit 10.21 to the Company's Form 10-K filed on March 16, 2011).
10.17*		Amendment to the BPZ Energy, Inc. (a/k/a BPZ Resources, Inc.) 2007 Long-Term Incentive Compensation Plan (incorporated by reference to exhibit 10.22 to the Company's Form 10-K filed on March 16, 2011).
10.18*		Second Amendment to the BPZ Energy, Inc. (a/k/a BPZ Resources, Inc.) 2007 Long-Term Incentive Compensation Plan, dated April 20, 2011 (incorporated by reference to exhibit 10.2 to the Company's Form 10-Q filed on August 8, 2011).
10.19		BPZ Resources, Inc. Employee Stock Purchase Plan (incorporated by referenced to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2011 filed with the Commission on August 9, 2011).

10.20		$75,000,000 Credit Agreement by and among BPZ Resources, Inc., and its subsidiaries BPZ Energy LLC, and BPZ Exploración & Producción S.R.L., as guarantors and Credit Suisse AG Cayman Islands Branch, as administrative agent and lender, Standard Bank PLC, as lender and mandated lead arranger, and Credit Suisse International, as lead arranger, dated as of July 6, 2011 (incorporated by reference to exhibit 10.1 to the Company's Form 10-Q filed on August 8, 2011).

10.21		First Amendment to $40,000,000 Credit Agreement by and among Empresa Electrica Nueva Esperanza S.R.L., as Borrower, and BPZ Resources, Inc., and BPZ Exploración & Producción S.R.L., as Guarantors and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent, and Credit Suisse International, as Arranger, dated as of January 27, 2011 (incorporated by reference to Exhibit 10.27 to the Company's Form 10-K filed on March 14, 2012).
10.22		Second Amendment to $40,000,000 Credit Agreement by and among Empresa Electrica Nueva Esperanza S.R.L., as Borrower, and BPZ Resources, Inc., and BPZ Exploración & Producción S.R.L., as Guarantors and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent, and Credit Suisse International, as Arranger, dated as of January 27, 2011 (incorporated by reference to Exhibit 10.28 to the Company's Form 10-K filed on March 14, 2012).
10.23		Third Amendment to $40,000,000 Credit Agreement by and among Empresa Electrica Nueva Esperanza S.R.L., as Borrower, and BPZ Resources, Inc., and BPZ Exploración & Producción S.R.L., as Guarantors and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent, and Credit Suisse International, as Arranger, dated as of January 27, 2011 (incorporated by reference to Exhibit 10.29 to the Company's Form 10-K filed on March 14, 2012).
10.24		Fourth Amendment to $40,000,000 Credit Agreement by and among Empresa Electrica Nueva Esperanza S.R.L., as Borrower, and BPZ Resources, Inc., and BPZ Exploración & Producción S.R.L., as Guarantors and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent, and Credit Suisse International, as Arranger, dated as of January 27, 2011 (incorporated by reference to Exhibit 10.1 to the Company's Form 10-Q filed on May 10, 2012).
10.25		Amendment to the Credit Agreement dated January 27, 2011 among Empresa Electrica Nueva Esperanza S.R.L.as borrower and Credit Suisse AG Cayman Island Branch as administrative agent (incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed on January 2, 2013).
10.26		First Amendment to $75,000,000 Credit Agreement by and among BPZ Resources, Inc., and its subsidiaries BPZ Energy LLC, and BPZ Exploración & Producción S.R.L., as guarantors and Credit Suisse AG, Cayman Islands Branch, as administrative agent and lender, Standard Bank PLC, as lender and mandated lead arranger, and Credit Suisse International, as lead arranger, dated as of July 6, 2011 (incorporated by reference to Exhibit 10.30 to the Company's Form 10-K filed on March 14, 2012).
10.27		Second Amendment to $75,000,000 Credit Agreement by and among BPZ Resources, Inc., and its subsidiaries BPZ Energy LLC, and BPZ Exploración & Producción S.R.L., as guarantors and Credit Suisse AG, Cayman Islands Branch, as administrative agent and lender, Standard Bank PLC, as lender and mandated lead arranger, and Credit Suisse International, as lead arranger, dated as of July 6, 2011 (incorporated by reference to Exhibit 10.31 to the Company's Form 10-K filed on March 14, 2012).
10.28		Third Amendment to $75,000,000 Credit Agreement by and among BPZ Resources, Inc., and its subsidiaries BPZ Energy LLC, and BPZ Exploración & Producción S.R.L., as guarantors and Credit Suisse AG, Cayman Islands Branch, as administrative agent and lender, Standard Bank PLC, as lender and mandated lead arranger, and Credit Suisse International, as lead arranger, dated as of July 6, 2011 (incorporated by reference to Exhibit 10.32 to the Company's Form 10-K filed on March 14, 2012).

10.29		Fourth Amendment to $75,000,000 Credit Agreement by and among BPZ Resources, Inc., and its subsidiaries BPZ Energy LLC, and BPZ Exploración & Producción S.R.L., as guarantors and Credit Suisse AG, Cayman Islands Branch, as administrative agent and lender, Standard Bank PLC, as lender and mandated lead arranger, and Credit Suisse International, as lead arranger, dated as of July 6, 2011 (incorporated by reference to Exhibit 10.2 to the Company's Form 10-Q filed on May 10, 2012).

10.30		Fifth Amendment to $75,000,000 Credit Agreement by and among BPZ Resources, Inc., and its subsidiaries BPZ Energy LLC, and BPZ Exploración & Producción S.R.L., as guarantors and Credit Suisse AG, Cayman Islands Branch, as administrative agent and lender, Standard Bank PLC, as lender and mandated lead arranger, and Credit Suisse International, as lead arranger, dated as of July 6, 2011 (incorporated by reference to Exhibit 10.1 to the Company's Form 10-Q filed on August 9, 2012).
10.31		Amendment to the Credit Agreement dated July 6, 2011 among BPZ Exploracion & Produccion S.R.L.as borrower and Credit Suisse AG Cayman Island Branch as administrative agent (incorporated by reference to Exhibit 10.2 to the Company's Form 8-K filed on January 2, 2013).
10.32		Stock Purchase Agreement Among BPZ Energy International Holdings, L.P. and BPZ Energy LLC, as Sellers, BPZ Resources, Inc., as Borrower, and Pacific Stratus Energy S.A., as Buyer, and Pacific Stratus International Energy Ltd., as Pre Lender, Concerning BPZ Norte Oil S.R.L., dated April 27, 2012 (incorporated by reference to Exhibit 10.3 to the Company's Form 10-Q filed on May 10, 2012).
10.33		Joint Operating Agreement among BPZ Exploración & Producción S.R.L. and BPZ Norte S.R.L. for the Exploration - Exploitation License Block Z-1 Offshore, Peru, signed as of April 27, 2012 and effective as of the Effective Date (as defined therein) (incorporated by reference to Exhibit 10.4 to the Company's Form 10-Q filed on May 10, 2012).
10.34		Carry agreement made on April 27, 2012 and effective as of the Carry Start Date (as defined therein) between BPZ Exploración & Producción S.R.L. and BPZ Norte S.R.L. (incorporated by reference to Exhibit 10.5 to the Company's Form 10-Q filed on May 10, 2012).
10.35		Amendment to the Stock Purchase Agreement Among BPZ Energy International Holdings, L.P. and BPZ Energy LLC, as Sellers, BPZ Resources, Inc., as Borrower, and Pacific Stratus Energy S.A., as Buyer, and Pacific Stratus International Energy Ltd., as PRE Lender, Closing Letter Concerning BPZ Norte Oil S.R.L., dated December 26, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed on January 2, 2013).
10.36*		Form of Performance Share Award Agreement (incorporated by reference to Exhibit 10.38 to the Company's Form 10-K filed on March 12, 2014).
10.37*		Third Amendment to the BPZ Energy, Inc. (n/k/a BPZ Resources, Inc.) 2007 Long-Term Incentive Compensation Plan, dated April 20, 2011, filed herewith.
10.38*		Amendment to the BPZ Energy, Inc. (n/k/a BPZ Resources, Inc.) 2007 Directors Compensation Incentive Plan, filed herewith.
10.39*		Fourth Amendment to the BPZ Energy, Inc. (n/k/a BPZ Resources, Inc.) 2007 Long-Term Incentive Compensation Plan, dated April 20, 2011, filed herewith.

12.1		Calculation of ratio of earnings to fixed charges, filed herewith.
14.1		Code of Ethics for Executive Officers (incorporated by reference to Exhibit 14.1 to Form 10-KSB/A filed on September 26, 2006).
21.1		Subsidiaries of the Registrant, filed herewith.

23.1		Consent of Independent Registered Public Accounting Firm, filed herewith.
23.2		Consent of Independent Petroleum Engineers and Geologists, filed herewith.
31.1		Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.2		Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
32.1		Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, filed herewith.
32.2		Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, filed herewith.
99.1		Report of Netherland, Sewell & Associates, Inc., filed herewith.
101.INS		XBRL Instance Document. (filed herewith)
101.SCH		XBRL Schema Document. (filed herewith)
101.CAL		XBRL Calculation Linkbase Document. (filed herewith)
101.LAB		XBRL Label Linkbase Document. (filed herewith)
101.PRE		XBRL Presentation Linkbase Document. (filed herewith)

101.DEF		XBRL Definition Linkbase Document. (filed herewith)

* - Management Contract or Compensatory Plan or Arrangement.