MAGELLAN PETROLEUM CORP /DE/
Form 10-K
October 13, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended June 30, 2015,
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
for the transition period from __________ to __________
Commission file number 001-5507
Magellan Petroleum Corporation
(Exact name of registrant as specified in its charter)

Delaware	06-0842255
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1950, Denver, Colorado	80203
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (720) 484-2400
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, par value $0.01 per share	NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 þ 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 Act.:

Large accelerated filer o	Accelerated filer o	Non-accelerated filer o	Smaller reporting company þ
		(Do not check if a smaller reporting company)	

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

The aggregate market value of the common equity held by non-affiliates of the registrant, based on the $7.280 closing price per share of the registrant's common stock as reported by the NASDAQ Capital Market, as of December 31, 2014 (the last business day of the most recently completed second fiscal quarter) was $37,845,881. For the purpose of this calculation, shares of common stock held by each director and executive officer and by each person who owns ten percent or more of the outstanding shares of common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for any other purpose. The closing price and number of shares have been retroactively adjusted to reflect the one share for eight shares reverse stock split complete on July 10, 2015.

As of October 9, 2015, the registrant had 5,702,532 shares of common stock outstanding, which is net of 1,209,389 treasury shares held by the registrant. These amounts reflect the one share for eight shares reverse split of the registrant's outstanding and treasury shares of common stock, respectively, completed on July 10, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the 2015 annual meeting of stockholders to be filed within 120 days after June 30, 2015, are incorporated by reference in Part III of this Form 10-K to the extent stated herein.

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PART I

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

OVERVIEW OF THE COMPANY

Magellan Petroleum Corporation (the "Company" or "Magellan" or "MPC" or "we") is an independent oil and gas exploration and production company focused on the development of CO_2-enhanced oil recovery ("CO_2-EOR") projects in the Rocky Mountain region. Historically active internationally, Magellan also owns significant exploration acreage in the Weald Basin, onshore UK, and an exploration block, NT/P82, in the Bonaparte Basin, offshore Northern Territory, Australia, which the Company currently plans to farmout; and an 7.4% ownership stake in Central Petroleum Limited (ASX: CTP) ("Central"), a Brisbane based junior exploration and production company that operates one of the largest holdings of prospective onshore acreage in Australia.

The Company conducts its operations through three wholly owned subsidiaries corresponding to the geographical areas in which the Company operates: Nautilus Poplar LLC ("NP") in the US, Magellan Petroleum (UK) Limited ("MPUK"), and Magellan Petroleum Australia Pty Ltd ("MPA").

The Company has incurred losses from operations for the year ended June 30, 2015, of $30.3 million. In addition, during the fiscal year working capital has decreased from $25.6 million at June 30, 2014, to $3.9 million at June 30, 2015, and the Company's cash balance has decreased to $1.1 million as of June 30, 2015. The Company continues to experience liquidity constraints and has begun selling certain of its non-core assets to fund its operations. However, proceeds from these asset sales may not provide sufficient liquidity to fund operations for the next twelve months. These factors raise substantial doubt about the Company's ability to continue as a going concern.

Magellan was founded in 1957 and incorporated in Delaware in 1967. The Company's common stock has been trading on the NASDAQ since 1972 under the ticker symbol "MPET".

Our principal offices are located at 1775 Sherman Street, Suite 1950, Denver, Colorado, 80203, and our telephone number is (720) 484-2400.

On July 10, 2015, the Company completed a one share-for-eight shares reverse stock split with respect to the Company's common stock. Amounts of shares of common stock and per share prices with respect to common stock have been adjusted in this report to reflect the reverse stock split.

STRATEGY

Our strategy is to enhance shareholder value by maximizing the value of our existing assets. Our portfolio of operations includes several early stage oil and gas exploration and development projects, the successful development of which requires significant capital, as well as significant engineering and management resources. We are committed to efficiently investing financial, technical and management capital into these projects to establish their technical and economic viability, which in turn could create significant potential value for our shareholders.

SIGNIFICANT DEVELOPMENTS IN FISCAL YEAR 2015

During fiscal year 2015, the Company achieved a number of key milestones in the strategy of creating value from our existing assets.

Corporate Events

NASDAQ Listing Compliance. On January 27, 2015, the Company received a letter from The NASDAQ Stock Market LLC ("NASDAQ") indicating that the Company's common stock did not meet the minimum bid price of $1.00 per share required for continued listing on The NASDAQ Capital Market. On July 27, 2015, NASDAQ notified the Company that it had regained compliance with the minimum bid price requirement. Instrumental in allowing the Company to regain compliance with the NASDAQ listing rules was the Company's 1-for-8 reverse stock split, completed on July 10, 2015. We believe that the Company's platform as a public entity carries certain intrinsic value and that stockholders benefit from the enhanced liquidity provided by the listing of the Company's common stock on NASDAQ. However, on October 9, 2015, the closing market price

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for the Company's common stock was $0.70 per share, and there is no assurance that NASDAQ listing compliance can be maintained.

WTSB term loan. On June 30, 2015, the senior secured revolving loan facility (the “Revolving Loan Facility”), which NP, a wholly owned subsidiary of Magellan, which holds the Company's interests in the Poplar Field, entered into on September 17, 2014, with West Texas State Bank ("WTSB"), was converted into a single term loan (the "Term Loan"), its maturity extended, and the grant of security interests by NP in favor of WTSB reaffirmed. The Revolving Loan Facility was due to mature on September 30, 2015, and the outstanding balance amounted to $5.5 million. The total amount of the Term Loan is also $5.5 million and no additional draws may be made. The term of the Term Loan is five years and is due on June 30, 2020. During the first twelve months of the Term Loan, only interest will be payable and the principal amount will be amortized over the remaining four years of the life of the Term Loan. The interest payments of the Revolving Loan Facility and the Term Loan were based on the prime rate and the prime rate plus 1.50%, respectively, with a floor rate of 3.25% and 4.75%, respectively. We believe that the conversion of the Revolving Loan Facility into a Term Loan enables the Company to extend the maturity date of the loan and to benefit from one year of interest only payments, which we believe will provide the Company with additional flexibility in collecting additional data from the CO_2-EOR pilot program at Poplar and the economic evaluation of the project.

Market Value of Central Petroleum’s Shares. As partial consideration for the sale of the Company’s onshore Australia assets in fiscal year 2014, the Company received approximately 39.5 million shares of Central Petroleum ("Central"), a small oil and gas company listed on the Australian Securities Exchange (ASX: CTP), equivalent to an ownership interest in Central of approximately 11%. During the twelve months ended June 30, 2015, the market price of Central’s common stock declined significantly, resulting in a significant reduction in the value of our interest, which was further negatively impacted by unfavorable fluctuation in the exchange rate between US and Australian dollars. The decline in Central’ s market trading price was similar to the declines in the market trading prices of other small public companies operating in the oil and gas sector in Australia, which partially reflect the drop in commodity prices over the same period. During fiscal 2015, Central acquired 50% of the Mereenie field in Australia and based on the potential development of a pipeline to connect the Northern Territory and New South Wales gas pipeline networks, Central may benefit from the higher priced gas markets of Eastern Australia and unlock significant reserves. As a result of the Company’s currently constrained liquidity position, we currently consider the shares of Central as a source of liquidity to finance the operations of the Company.

ATM Facility and Shelf Registration. On December 24, 2014, the Company implemented an "at-the-market" ("ATM") facility under which the Company can raise up to $10 million through the issuance of new shares of common stock into the market. The ATM facility is registered under the Company's "shelf" registration statement (the "Shelf") on Form S-3, which was filed with the U.S. Securities and Exchange Commission on November 17, 2014, and which went effective on December 3, 2014. The Shelf registers the issuance of up to $100 million in equity securities of the Company. The rationale for implementing the ATM facility and the Shelf included the potential financing of the cash payment of dividends on the Company's Series A Preferred Stock, in particular when the conversion price of the Series A Preferred Stock may be lower than the market price of the Company’s common stock and therefore providing an attractive arbitrage, the potential funding of the Company's CO_2-EOR business at Poplar or in Utah, and general financial flexibility. As of the filing date of this report, no securities have been issued under either the Shelf or the ATM facility.

Repurchase of Common Stock and Options. On October 10, 2014, when oil commodity prices and the market trading price for the Company's common stock were substantially higher than current levels, Magellan entered into an Options and Stock Purchase Agreement (the "Hastings Agreement") with William H. Hastings, a former executive officer and director of the Company and a beneficial owner of more than 5% of the Company’s common stock as of October 10, 2014. The Hastings Agreement provided for the repurchase by the Company from Mr. Hastings of 31,250 shares of the Company’s common stock and fully vested and exercisable options to acquire 189,062 shares of the Company’s common stock. The gross proceeds that were paid to Mr. Hastings on October 17, 2014, pursuant to the Hastings Agreement were based on the then current share price and totaled $1.4 million and were subject to applicable tax withholdings. The options repurchased represent 56% of the total of 339,062 options previously granted to Mr. Hastings in December, 2008 as part of his compensation as an executive officer of the Company (the “Options”).

Following the repurchase, Mr. Hastings still owns 150,000 fully vested Options, which have an exercise price of $9.60 and an expiration date of December 31, 2015. Management believed that the Hastings Agreement allowed the Company to remove a substantial overhang on the Company's stock created by the potentially dilutive impact of Mr. Hastings's stock options at a price that was believed to be attractive at the time.

Progress on Key Projects

Poplar CO_2-EOR pilot project. During fiscal year 2015, the Company continued to monitor, collect data, and develop the five-well CO_2-EOR pilot program at Poplar that began in fiscal year 2014. In May 2015, the Company determined that CO_2-EOR is a technically viable technique for recovery of hydrocarbons from the Charles formation at Poplar. Based on the

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results of the CO_2-EOR pilot project to date and our analysis of the data from the pilot as integrated into our reservoir simulation model, we believe that utilization of the CO_2-EOR technique on a full field basis at Poplar could provide access to substantial additional hydrocarbon resources that could result in attractive financial returns from production over a forty year period.

The CO_2-EOR pilot project consisted of drilling four producer wells and one CO_2 injection well to a total depth of approximately 5,800 feet, completing the wells in the B-2 zone of the Charles formation, performing water shut-off treatments in all five wells, and installing the necessary surface facilities and CO_2 injection equipment. In August 2014, the Company commenced the continuous injection of volumes of CO_2 into the B-2 zone of the Charles formation through the injector well, EPU 202-IW. In early October 2014, the Company opened for production the four producer wells. Initial production from these wells was mainly water with negligible traces of oil. In early January 2015, two of the four pilot producer wells began to exhibit oil production with improving oil cuts. Since then, oil production has increased in three of the four producer wells in response to CO_2 injection, with a peak oil production rate of approximately 50 bopd. In June 2015, the Company stopped injecting CO_2 and started injecting water, pursuant to a water alternating gas process (the "WAG" process). The purpose of a WAG process is to optimize the sweep efficiency of the CO_2 by reducing the total volume of CO_2 required to mobilize the oil that remains in the reservoir. Throughout the year, all data gathered by the Company from the pilot has been continuously integrated into the Company's reservoir simulation model and reviewed by third party consultants. Based on the reservoir simulation model, the Company then created a potential development plan for the Charles formation of Poplar using CO_2-EOR, which forms the basis of the Company's estimate of the substantial additional hydrocarbons that may be produced from CO_2-EOR. The development plan details the various phases of drilling activity, including the number of production and injection wells necessary, the amount of CO_2 required to "sweep" the Charles formation, and the estimated resulting oil production over approximately a forty year period. The results of the reservoir simulation model also suggest that the utilization rate of CO_2, which represents the amount of CO_2 required to recover volumes of oil from Poplar on a unit basis, and which represents the sweep efficiency of the CO_2-EOR technique, is in line with several other projects to which the CO_2-EOR technique has been applied.

In addition, during fiscal 2015, the Company evaluated the availability, feasibility, and costs of certain key aspects of the potential development plan of Poplar using CO_2-EOR, including the sources of CO_2 which could be available to the project within a reasonable distance, the pipeline to transport the CO_2 from its potential sources to Poplar, and the surface facilities and their ancillary requirements, and integrated this information in the development plan of Poplar. As regards to sources of CO_2, we identified two potential suppliers and initiated discussions with each, and believe that a long term, reliable source of CO_2 at a reasonable price could be available to the Company. The Company then integrated all the information available to analyze its potential development plan for Poplar using CO_2-EOR and concluded that the development of Poplar using CO_2-EOR will require significant capital to invest, the amount of which we estimate at several hundreds of millions of dollars, and that the economic viability will depend on a recovery of oil prices. Considering that the development of Poplar is expected to span over several decades, we believe that this asset should be attractive to potential investors that would have a long term view of the oil industry and commodity prices. Also considering the significant capital requirements of the potential development of Poplar and in light of the current capitalization of the Company, we believe that a partner is needed to support the development of this project, both financially and operationally. This conclusion contributed to the Company's decision to initiate a strategic alternative review process in June 2015.

Utah CO2. During fiscal 2015, Magellan formed Utah CO2 LLC ("Utah CO2"), a majority owned subsidiary focused on the acquisition of sources of CO_2 in Utah and identification of potential candidate fields for CO_2-EOR projects. On December 1, 2014, Magellan, through Utah CO2, entered into an option agreement (the "Utah CO2 Option Agreement") to either i) acquire a large CO_2 reservoir called Farnham Dome located in Carbon County, Utah or ii) enter into an agreement to purchase uncontracted CO_2 volumes at a fixed price (the "CO_2 Purchase Agreement"). In May 2015, Utah CO2 elected to exercise the right to enter into the CO_2 Purchase Agreement, the key terms of which are to be consistent with the terms detailed in the Utah CO2 Option Agreement, which included a fifty year term, an attractive CO_2 price per mcf, the exclusive access to CO_2 volumes recoverable from Farnham Dome for CO_2-EOR projects in Utah, and no CO_2 purchase obligations for the first three years. Based on our preliminary analysis, several oil fields located within approximately a 100 mile radius of Farnham Dome could be attractive candidates to become CO_2-EOR projects. Considering that long term, cost competitive access to CO_2 is a critical component to enable the development of oil fields using CO_2-EOR technique, the CO_2 Purchase Agreement, if finalized and executed, is expected to provide Utah CO2 with exposure to and an investment opportunity with several potential CO_2-EOR projects in Utah. We believe that the investment in this new venture is complementary to the Poplar asset, and since no CO_2 purchase obligations are required for at least three years under the terms of the CO_2 Purchase Agreement, Utah CO2 is expected to provide a cost effective way to grow the Company's activities in CO_2-EOR.

UK - Horse Hill. Magellan currently maintains non-operating interests in Petroleum Exploration and Development Licenses ("PEDLs") 137 and 246, representing approximately 12 thousand net acres, that may be prospective for conventional oil and gas targets. PEDLs 137 and 246 cover the Horse Hill structure. Magellan is encouraged by the technical analysis

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performed on the Horse Hill prospect by its partner, Horse Hill Development Limited (“HHDL”), a 65% interest owner of the Horse Hill-1 well ("HH-1") and UK Oil & Gas Investments PLC, (“UKOG”), which through its direct and indirect investments controls approximately 20.4% of HH-1. HH-1, spud in August 2014, confirmed that the Upper Jurassic section is thermally mature (i.e., in the oil window) and contains two thick limestone intervals that may act as conventional reservoirs for a significant oil play in the Weald Basin. This confirmation suggests that the Upper Jurassic throughout the greater Weald Basin is also thermally mature, and therefore serves as an important data point in evaluating the potential of the Company's Central Weald licenses. HH-1 is expected to be put on a production test from the Portland Sandstone section in the first half of fiscal year 2016, pending regulatory approvals. Pursuant to a farmout agreement executed in December 2013, Magellan owns a 35% working interest in the HH-1 well and is being carried for its share of well costs through testing and completion.

UK - Central Weald Basin Licenses. During fiscal year 2015, Celtique Energie Weald Limited ("Celtique"), the equal co-owner with the Company, and operator of the three licenses in the central Weald Basin, PEDLs 231, 234, and 243, initiated a legal proceeding against the Company for the payment of an advancement of estimated expenses in the amount of $2 million in connection with the first exploratory well, the Broadford Bridge-1 well that was planned to be spud on PEDL 234 during the year. Celtique applied for a summary judgment in the UK court of law and in June 2015, the judge rejected the application primarily due to Magellan’s real prospect of defending the claim from Celtique. Among other things, Magellan disputes that the amount of the cash calls was in fact going to be spent at the time of the cash call. The judge also awarded GBP 60 thousand to Magellan to be paid by Celtique for the reimbursement of certain costs the Company incurred in relation to the litigation. As of the filing date of this report, the litigation between Celtique and Magellan continues. For additional information, see Note 14 - Commitments and Contingencies - Celtique Litigation, in the Notes to the Consolidated Financial Statements included in this report. PEDLs 231, 234, and 243 represent approximately 124 thousand net acres that may be prospective for conventional and unconventional oil and gas development from the Kimmeridge Clay, Liassic, and other formations. These licenses are subject to drill-or-drop obligations and will expire in June, 2016, unless such obligations are met.

Other UK Licenses. During fiscal year 2015, Magellan continued to reduce its interest in its licenses on the periphery of the Weald Basin. In April 2015, the Company sold for nominal consideration its 40% interest in PEDL 126, the exploration license that contains the Markwells Wood-1 wellbore ("MW-1"). By selling the license and the wellbore, the Company eliminated approximately $346 thousand of asset retirement obligations related to MW-1. Following the sale of its interest in PEDL 126, the Company continues to hold a 23% interest in PEDL 1916, located offshore southern UK, near the Isle of Wight.

Australia NT/P82. During the fiscal year 2015, the Company sought a suitable farmout partner experienced in offshore drilling to drill and carry Magellan for the work commitment obligation in exchange for a portion of its working interest and operatorship of the NT/P82 exploration block in the Bonaparte Basin. However, the Company was unable to complete a farmout agreement during the year. In June 2015, the National Offshore Petroleum Titles Administrator (“NOPTA”) approved the variation of the minimum work requirements to be conducted by May 12, 2016, from the drilling of a well in the block to a 600 km^2 3-D seismic program. NOPTA also advised that a suspension and extension of the work requirement for the permit year ending May 12, 2015, and a potential delay of the 3-D seismic program to be conducted during the permit year ending May 12, 2016, may be considered. This variation is expected to allow the Company greater flexibility in obtaining partner(s) and executing a farmout of this exploration block.

Financial Performance

As a result of the sale of the Amadeus Basin assets in March 2014, results of operations related to these assets have been reclassified as discontinued operations. Accordingly, the revenue and adjusted EBITDAX amounts presented immediately below for fiscal years 2014, and 2015, exclude the impact of these assets on such amounts.

Revenues. Revenues for the fiscal year ended June 30, 2015, totaled $4.5 million, compared to $7.6 million in the prior year, a decrease of 41%. The $3.1 million decrease in revenue from the prior year was primarily due to both a decrease in the average sales price realized from production from the field ($2.5 million) and a decrease in production volumes ($0.6 million) resulting from i) the natural production decline of the Poplar field, and ii) a reduction in the level of workover activity. The decrease in realized price resulted from a decrease in WTI, the benchmark price during

the period.
Loss from continuing operations. Loss from continuing operations totaled $43.4 million ($7.83/basic share), compared to loss from continuing operations of $10.0 million ($2.07/basic share) in the prior year. The increase in loss from continuing operations was primarily the result of an impairment loss on proved properties of $17.4 million and a loss recognized on our available-for-sale investment in securities of $15.1 million in the current year.
Adjusted EBITDAX. Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) was negative $7.7 million, compared to negative $5.6 million in the prior fiscal year, a change of 39%. The decline in Adjusted EBITDAX resulted from an decrease in revenues of $3.1 million, partially offset by a decrease

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in lease operating expense of $1.2 million and a reduction in general and administrative expense (excluding stock based compensation and foreign transaction loss) of $0.2 million.

Cash. As of June 30, 2015, Magellan had $1.1 million in cash and cash equivalents, compared to $16.4 million at the end of the prior fiscal year. The decrease of $15.4 million was the result of net cash used in operating activities of $8.6 million, net cash used in investing activities of $9.3 million, net cash provided by financing activities of $3.2 million, and a decrease in cash from the effect of changes in exchange rates of $0.7 million. The $8.6 million of net cash used in operating activities was primarily due to a $0.6 million operating loss at Poplar and general and administrative expenses, net of stock based compensation expense and foreign transaction loss of $7.1 million. The $9.3 million of net cash used in investing activities was primarily the result of $9.1 million of capital expenditures, the majority of which related to the CO_2-EOR pilot at Poplar.

Securities available-for-sale. As of June 30, 2015, Magellan had $4.2 million in securities available for sale, consisting of the Company's investment in shares of Central stock. The Company faces no restrictions other than insider trading restrictions relevant to this stock and can liquidate a portion or all of these shares if needed to fund its other projects or obligations.

OUTLOOK FOR FISCAL YEAR 2016

2016 will be a year of transition and transformation for Magellan. Over the past four years, we have focused our efforts on establishing the potential value of Poplar, by demonstrating the technical viability of recovering incremental volumes of oil using the CO_2-EOR technique. Although continuing the CO_2-EOR pilot could further refine our technical evaluation of the project, we believe that considering i) we estimate that the development of Poplar on a full field basis using CO_2-EOR technique will require several hundreds of millions of dollars, ii) the current liquidity position of the Company, and iii) the currently depressed commodity price environment, we believe that the Company and Poplar need the technical and financial support of a larger partner. Consequently, on June 5, 2015, the Company formed a special committee of independent members of the Board of Directors of the Company (the "Special Committee") to consider various strategic alternatives potentially available to the Company. The formation of the Special Committee was not in response to any proposal received by the Company or an approach by a third party. The Special Committee is authorized to identify, consider, negotiate, and potentially implement all strategic alternatives reasonably available to the Company, including, but not limited to, sales of some or all of the assets of the Company, joint ventures, a recapitalization, and a sale or merger of the Company. The Special Committee engaged Petrie Partners, LLC as financial advisor to assist in the consideration of such matters. The Special Committee has been and continues to be actively engaged in the strategic alternative review process, and is currently in discussions with various potential parties regarding a potential transaction or series of transactions. However, as of the filing date of this report, no decision on any particular strategic alternative or transaction has been reached, and there is no assurance that any future agreement will be reached, or that any future sale or other strategic alternative transaction or transactions will occur.

Over the past four years, the Company also conducted a gradual rationalization of its international portfolio, the objective of which was to allow the Company to evaluate the potential value of these assets, monetize them at an optimal time to maximize value for shareholders, and to finance the Company’s other activities. During the next year we expect to complete this rationalization process by executing a farmout agreement for our offshore Australia block, NT/P82, monetize our interest in Central to finance the Company’s activities, and we will endeavor to resolve the litigation with Celtique, which currently encumbers a potential sale or farmout process of some of our UK assets.

CO_2-EOR Pilot Project

During fiscal year 2016, the Company intends to continue collecting data from the CO_2-EOR pilot and refine its technical evaluation, and through the strategic alternative review process, seek to identify a partner to enable the development of Poplar using the CO_2-EOR technique.

Based on the data collected from, and the initial results of the Company’s evaluation of the CO_2-EOR pilot, we believe that the CO_2-EOR technique can be effective at Poplar to recover additional volumes of oil. The Company will now focus its efforts on refining its evaluation. In June 2015, the Company stopped injecting CO_2 and started injecting water, pursuant to a WAG process, the purpose of which process is to optimize the sweep efficiency of the CO_2 by reducing the total volume of CO_2 required to mobilize the oil that remains in the reservoir. The Company does not expect to incur further significant costs in relation to the CO_2-EOR pilot in excess of the ongoing expenses to operate the pilot and the CO_2 costs of the CO_2-EOR pilot.

The primary focus of the Company during the fiscal year ending June 30, 2016, will be to obtain a potential partner to support the future development of Poplar or monetize Poplar. Based on the results of the Company's reservoir simulation model, we created a plan for the first phase of the full field development of Poplar through CO_2-EOR, which development plan envisions the drilling of approximately 150 wells including both injection and production wells, the construction of surface

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facilities, the laying of a pipeline from the long term source of CO_2 to Poplar, and the execution of a contract for a source of CO_2 which remains in discussions. By integrating the results of the reservoir simulation model with the main elements of the first phase development plan into the Company's financial model, we estimated that the cumulative funding required over the initial development phase of the project would be several hundreds of millions of dollars. Consequently, the Company believes that, considering the current commodity price environment and market capitalization of the Company, it may not be able to raise the financing required to develop Poplar using CO_2-EOR on a full field basis and therefore it is in the best interests of the Company's shareholders for the Special Committee to consider strategic alternatives as discussed above and engage a financial advisor to support its efforts to complete a transaction with a partner to maximize the value of Poplar.
In addition, the Company is planning to implement certain cost saving initiatives with the objective of reducing the operating losses from Poplar and endeavoring to achieve break-even cash flows from Poplar at current commodity price levels.

UK - Horse Hill

HHDL, our partner in the Horse Hill well, is planning to conduct a flow test of the conventional formations, particularly the Portland Sandstone and the tight underlying Jurassic-aged formations. Magellan is fully carried by HHDL for the cost of performing the flow test under the terms of the farmout agreement with HHDL. Once the Company receives the results of the flow test, the Company will determine what it believes is the most appropriate path to generate value for its shareholders, which path may include a sale or further farmout agreement of the Company's interest in the Horse Hill well and PEDLs 137 and 246, and which will reflect consideration of the overall political and social environment in the UK with respect to conventional and unconventional oil and gas developments.

UK - Central Weald Licenses
As regards to PEDLs 231, 234, and 243, which are co-owned with Celtique, the Company will endeavor to resolve the pending litigation with Celtique, which resolution could include a potential buyout by one of the two co-owners, or a combined sale process. Considering the pending litigation and that these licenses are subject to drill-or-drop obligations with license terms ending June 30, 2016, there is a risk that the litigation with Celtique will not be resolved in time to avoid the relinquishment of these licenses.

NT/P82, Offshore Australia
Based on the results of the interpretation of the seismic data and following the variation to the terms of the license, the Company will continue to seek to identify a farmout partner experienced in offshore drilling. In July 2015, the Company engaged RFC Ambrian as a financial advisor to support the Company's efforts to conduct a farmout process. As part of the potential farmout, the Company expects to relinquish a portion of its working interest in, and operatorship of, NT/P82, in exchange for a commitment from the partner to meet the work requirements under the terms of the license and potential renewal term. Given the high level of offshore drilling activity in the Bonaparte Basin, the network of installed gas infrastructure in the relative vicinity of our block, and the relatively shallow depths of water in the license, the Company believes it is well positioned to successfully execute a farmout agreement during fiscal year 2016.

Australia, Bonus Rights
The Company is entitled to bonus payments under two agreements; the value of the payments is contingent on certain operational results from assets the Company has sold in the past four fiscal years. First, under the terms of the Sale Agreement entered into on September 14, 2011, between Magellan Petroleum (N.T.) Pty Ltd, a wholly owned subsidiary of the Company, and Santos QNT Pty Ltd ("Santos QNT") and Santos Limited (collectively the "Santos Entities"), based upon sales of hydrocarbons from the Mereenie field ranging from 2,500 boepd to 10,000 boepd, bonus payments may range from AUD $5.0 million to cumulative potential payments of AUD $17.5 million (the "Mereenie Bonus"). Second, under the terms of the Share Sale and Purchase Deed dated February 17, 2014, between the

Company and Central, the Company is entitled to receive 25% of the revenues generated at the Palm Valley gas field from gas sales when the volume-weighted gas price realized at Palm Valley exceeds AUD $5.00/Gigajoule and AUD $6.00/Gigajoule for the first 10 years following the closing date of March 31, 2014, and for the following 5 years, respectively, with such prices to be escalated in accordance with the Australian CPI (the “Palm Valley Bonus”). For further information related to the Palm Valley Bonus, please refer to Note 2 - Sale of Amadeus Basin Assets of the Notes to Consolidated Financial Statements included in this report. The value of the rights to these bonus payments is not reflected on the Company’s financial statements, and the Company believes there is significant risk to the potential realization of value from these rights.

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The Australian government is currently considering awarding a contract to develop a pipeline interconnection between the Amadeus Gas Pipeline located in the Northern Territory, Australia and the New South Wales gas pipeline network, which is commonly referred to as the NT Gas Interconnect (“NEGI”). NEGI could allow additional gas to become available to supply the LNG terminals currently under construction in Queensland, which tend to benefit from higher sale prices than current gas sales contracts in the Northern Territory. If NEGI becomes certain, we believe that i) the probability of a potential increase in sales of hydrocarbons from the Mereenie field could increase, which could enhance the potential value of the Mereenie Bonus, and ii) the probability of an increase in the price of gas sales from Palm Valley above AUD $5.00 per Gigajoule could increase, which could enhance the potential value of the Palm Valley Bonus.

OPERATIONS

Magellan operates in the single industry segment of oil and gas exploration and production. We have three reportable geographic segments, NP, MPUK, and MPA, corresponding to our operations in the United States, the UK, and Australia, respectively. NP's oil and gas assets consist of its interests in Poplar in the Williston Basin. MPUK's oil and gas assets consist of various exploration licenses in or adjacent to the Weald Basin located onshore and offshore southern England. MPA's oil and gas assets consist of NT/P82, an exploration block in the Bonaparte Basin, offshore Australia, and an 7.4% ownership interest in Central as of October 9, 2015. The locations of the Company's key oil and gas properties are presented in the map below. For certain additional information about the Company's reportable segments, see Note 13 - Segment Information to the consolidated financial statements included in Part II, Item 8: Financial Statements and Supplementary Data of this report.

Magellan's Areas of Operations

United States - Poplar

In the US, Magellan owns Poplar, an oil field located in Roosevelt County, Montana. Our acreage position covers substantially all of Poplar Dome, the largest geologic structure in the western Williston Basin with multiple stacked formations with hydrocarbon resource potential.

The field was discovered in the 1950s by Murphy Oil, which actively explored and developed the Charles formation for two decades. By the time Magellan acquired Poplar in 2009, technological advances in oil and gas exploration allowed us to reevaluate Poplar's known formations and to discover new ones. The Charles formation at Poplar is highly prospective for development using the tertiary technique of CO_2-EOR. The Company's current primary focus at Poplar is the evaluation of the effectiveness of this technique through a CO_2-EOR pilot.

Poplar, as the Company defines it, is composed of a 100% working interest in the oil and gas leases within the East Poplar Unit ("EPU"), a federal exploratory unit in Roosevelt County, Montana, totaling approximately 18,000 acres, and the

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working interests in various oil and gas leases that are adjacent to or near EPU ("Northwest Poplar" or "NWP") totaling approximately 4,000 acres.

Our interests within EPU (also referred to herein as "Poplar") include a 100% operated working interest in the interval from the surface to the top of the Bakken/Three Forks formation (the "Shallow Intervals") and an operated working interest below those intervals ranging from 50% to 65%, which include the Bakken/Three Forks, Nisku, and Red River formations (the "Deep Intervals"). VAALCO Energy (USA), Inc. ("VAALCO") owns the remaining working interest in the Deep Intervals. Our interests within NWP are all operated and are the same as within EPU, except in certain leases in which the Company and VAALCO collectively own less than 100% of the working interest.

CO_2- EOR Pilot. Based on the Company's technical analysis, the production history of the field to date, and reference to analogous CO_2-EOR projects in the Williston Basin, management believes that the Charles formation at Poplar is an attractive candidate for CO_2-EOR, which has the potential to significantly increase the ultimate oil recovery of the field, resulting in increased reserves and oil production. To reduce the operational risk of implementing a full-field CO_2-EOR program at Poplar and to further validate the tertiary recovery technique on a full-field basis, the Company began a CO_2-EOR pilot project in the Charles formation in the first quarter of fiscal year 2014. The program consists of injecting CO_2 in an injection well for a period ranging between one and two years and assessing its impact on the oil production out of four production wells surrounding the injection well.

Shallow Intervals. In addition to the CO_2-EOR pilot in the Charles formation, the Company has existing conventional production in the Shallow Intervals, primarily from the Charles formation but also from the Tyler formation. At a later date, and subject to availability of capital resources, the Company may explore other formations within the Shallow Intervals prospectively for oil and gas production, including the Amsden, Piper, and Judith River formations.

Deep Intervals. Based on the results of three wells drilled into and completed in the Deep Intervals in 2012 and 2013, the Company has been able to evaluate the potential of various formations within the Deep Intervals, including the Bakken/Three Forks, Nisku, and Red River. Although commercial quantities of oil and gas were not encountered with these three wells, the results of cores and logs were encouraging. The Company may engage in further exploration of these formations at a later date, but has no current plans to do so.

United Kingdom

Magellan's UK position consists of interests in six exploration permits located in or adjacent to the Weald Basin, which is geographically situated southwest of London and which contains multiple unconventional and conventional oil and gas prospects. In the central Weald Basin, Magellan co-owns equally with Celtique three licenses (PEDLs 231, 234, and 243), representing 124 thousand net acres, that are prospective for unconventional oil and gas development from the Kimmeridge Clay and Liassic formations and may be prospective for conventional development in other formations. Celtique operates these licenses. On the periphery of the Weald Basin, Magellan maintains non-operated interests in three additional exploration licenses, representing an additional 15 thousand net acres, that may be prospective for conventional oil and gas targets.

Australia

NT/P82. In the Timor Sea, offshore Northern Territory, Australia, Magellan holds a 100% interest in the exploration permit NT/P82, which covers 2,500 square miles of the Bonaparte Basin in water ranging in depth from 30 to 500 feet. The Company conducted 3-D and 2-D seismic surveys over portions of the license area in December 2012 and, following processing and interpretation during fiscal years 2013 and 2014, is currently engaged in a process to obtain a suitable farmout partner to meet the revised work requirements in exchange for a portion of the Company's working interest in the permit. Based on the results of the 3-D and 2-D seismic surveys, the Company identified three potential prospects, including a potential reservoir in a structural trap against a fault line and a large amplitude-variation-with-offset anomaly. The Company is conducting a process to obtain a partner to evaluate these prospects further.

Central. Magellan is the owner of approximately 27.4 million shares of stock in Central, representing an approximate 7.4% ownership interest as of October 9, 2015. Central is a Brisbane-based junior exploration and production company that operates one of the largest holdings of prospective onshore acreage in Australia. Magellan received its shares in Central on March 31, 2014, as part of the consideration paid by Central to acquire Magellan's interests in the Palm Valley and Dingo gas fields. The Company's ownership of these shares is not subject to any trading restrictions imposed by Central, and the Company has the right to nominate one director to Central's board of directors. The Company's current nominee is J. Thomas Wilson, President and CEO of Magellan. Further information about Central can be found on Central's website at www.centralpetroleum.com.au, which is not incorporated by reference into this report and should not be considered part of this document.

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RESERVES

Estimates of reserves are inherently imprecise and continually subject to revision based on production history, results of additional exploration and development, price changes, the availability of financing and other factors. The following table presents a summary of our proved reserves as of June 30, 2015.

	Oil (Mbbls)	
United States Reserves:		
Proved developed producing ("PDP")	1,494	
Proved developed not producing ("PDNP")	746	
Proved undeveloped ("PUD")	—	
Total reserves	2,240	
PDP%	67	%
PDNP%	33	%
PUD%	—	%

Proved Undeveloped Reserves

As of June 30, 2015, the Company is not including PUD reserves in its total proved reserve estimates due to uncertainty regarding its ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves. The following table presents a summary of the changes in our PUDs during the year ended June 30, 2015:

	Total (Mbbls)	
Fiscal year opening balance	3,241	
Revisions due to pricing and performance of CO_2-EOR Pilot	(158	)
Revisions due to uncertainties regarding availability of development capital	(3,083	)
Fiscal year ended June 30, 2015 closing balance	—	

During the current fiscal year, the Company did not convert any proved undeveloped reserves to proved developed reserves or add additional PUD locations. As of June 30, 2015, we had no proved undeveloped reserves that had been on our books in excess of five years, and we had no material proved undeveloped locations that were more than one direct offset from an existing producing well.

During the fiscal year ended June 30, 2014, the Company added new proved undeveloped reserves of 3,241 Mbbls attributable to a 9-well drilling program at Poplar, which drilling program has been halted during fiscal year ending June 30, 2015, due to uncertainty regarding the Company's ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves. The nine well locations in this program were in the immediate vicinity of the five wells that have been recently drilled for the CO_2-EOR pilot project.

Probable Reserves

Estimates of probable reserves are inherently less certain than estimates of proved reserves. When estimating the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate that as likely as not will be achieved, as opposed to the reasonable certainty standard applicable to estimates of proved reserves. Estimates of probable reserves are continually subject to revision based on production history, results of additional exploration and development, price changes, the availability of development capital, and other factors, and are subject to substantially greater risk of not actually being realized by the Company.

We use deterministic methods to estimate probable reserve quantities, and when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the

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reasonable certainty criterion for proved reserves. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Consistent with our position on PUD reserves, due to the uncertainty of the Company's ability to continue as a going concern and the availably of financing to develop the probable reserves, at June 30, 2015 the Company has removed 1,937 Mbbls that otherwise would have been considered probable reserves.

Internal Controls Over Reserve Estimates

Our internal controls over the recording of proved and probable reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with regulations established by the SEC. The Company relies upon a combination of internal technical staff and third party consulting arrangements for reserve estimation and review.

Reserve estimates were prepared by Hector Wills of Mi3 Petroleum Engineering ("Mi3"), a Golden, Colorado, based petroleum engineering firm that regularly performs petroleum engineering services for the Company with respect to Poplar, for the fiscal years ended June 30, 2015, and 2014. Mr. Wills has nearly 20 years of operation and technical engineering experience in the oil and gas industry. Prior to his time with Mi3, he served as a reservoir engineer at Stimlab Inc, and prior to that as a drilling engineer at PDVSA Petroleos de Venezuela S.A.. Mr. Wills holds a PhD in Petroleum Engineering from the Colorado School of Mines. For both periods, the reserve estimates were audited by the Company's independent petroleum engineering firm, Allen & Crouch Petroleum Engineers ("A&C"). See "Third Party Reserve Audit" below. In addition, the preparation of the reserve estimates for both periods was subject to the oversight of our management and a summary review by the Audit Committee of our Board of Directors.

Third Party Reserve Audit

Reserve estimates were audited by A&C, an independent petroleum engineering firm. A copy of the summary reserve report of A&C is provided as Exhibit 99.1 to this Annual Report on Form 10-K. A&C does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis.

Detailed information regarding reserves, costs of oil and gas activities, capitalized costs, discounted future net cash flows, and results of operations is disclosed in the supplemental information (see Note 19 - Supplemental Oil and Gas Information (Unaudited)) to the consolidated financial statements included in Part II, Item 8 to this Form 10-K.

VOLUMES AND REALIZED PRICES

The following table summarizes volumes and prices realized from the sale of oil from properties in which we owned an interest during the periods presented. The table also summarizes operational costs per barrel of oil equivalent for the fiscal years ended:

	June 30, 2015	2014
United States:		
Volumes (Mbbls)	79	88
Average realized prices ($/bbl)	$56.44	$86.38
Lease operating ($/bbl)	$64.42	$71.10

Total production decreased from 88 Mbbls in fiscal year 2014, to 79 Mbbls in fiscal year 2015. The decrease was primarily the result of the natural production decline in the Poplar field and the impact of the suspension of the workover program in order to reduce expenditures. The average realized price at the Poplar field decreased to $56.44/bbl from $86.38/bbl in the prior year. The decrease was primarily the result of a decline in the benchmark crude oil price (WTI). The average WTI price declined 32% from the prior fiscal year, which was partially offset by a 10% improvement in the differential from the previous fiscal year. The Company does not currently engage in any oil and gas hedging activities. Lease operating expenses decreased to $64.42/bbl from $71.10/bbl in the prior year. The decrease is primarily related to lower production taxes, which are due to lower revenues as a result of lower commodity prices and reduced workover activity and maintenance on wells.

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PRODUCTIVE WELLS

Productive wells include producing wells and wells mechanically capable of production. The following table presents a summary of our productive wells, all of which were located in the United States at the Poplar field as of June 30, 2015:

	Productive Wells
United States:	
Gross oil wells [(1)]	37.0
Net oil wells [(2)]	35.1

[(1)] A gross well is a well in which the Company owns a working interest. Wells with one or more completions in the same bore hole are considered to be one well.

[(2)] The number of net wells is the sum of the fractional working interests owned in gross wells.

DRILLING ACTIVITY

The following table summarizes the results of our development and exploratory drilling during the fiscal years ended:

	June 30, 2015		2014	
	Productive [(2)]	Dry [(3)]	Productive [(2)]	Dry [(3)]
United States:				
Development wells, net [(1)]	—	—	5.0	—
Exploratory wells, net [(1)]	—	—	—	—
Total net wells	—	—	5.0	—

[(1)] The number of net wells is the sum of the fractional working interests owned in gross wells. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.

[(2)] A productive well is an exploratory, development, or extension well that is not a dry well.

[(3)] A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. Completion refers to installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been plugged and abandoned.

The following table summarizes the results, as of October 13, 2015, of our wells that were still in progress as of June 30, 2015:

	Still in Progress	
	Gross [(1)]	Net [(2)]
United States	2.0	2.0

[(1)] A gross well is a well in which the Company owns a working interest. Wells with one or more completions in the same bore hole are considered to be one well.

[(2)] The number of net wells is the sum of the fractional working interests owned in gross wells.

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ACREAGE

The following table summarizes gross and net developed and undeveloped acreage by geographic area at June 30, 2015.

	Developed [1]		Undeveloped [4]		Total	
	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]
United States (Poplar)	22,913	22,669	—	—	22,913	22,669
United Kingdom	80	28	293,749	138,420	293,829	138,448
Australia (NT/P82)	—	—	1,566,647	1,566,647	1,566,647	1,566,647
Total	22,993	22,697	1,860,396	1,705,067	1,883,389	1,727,764

[1] Developed acreage encompasses those leased acres assignable to productive wells. Our developed acreage that includes multiple formations may be considered undeveloped for certain formations but have been included as developed acreage in the presentation above.

[2] A gross acre is an acre in which the registrant owns a working interest.

[3] The number of net acres is the sum of the fractional working interests owned in gross acres.

[4] Undeveloped acreage encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves.

Of our 22,913 gross acres at Poplar, approximately 18,000 acres (79%) form a federal exploratory unit which is held by economic production from any one well within the unit. Currently, Poplar contains 37 producing wells.

TITLES TO PROPERTY, PERMITS AND LICENSES

Magellan maintains interests in its oil and gas properties through various contractual arrangements customary to the oil and gas industry and relevant to the local jurisdictions of its assets.

United States

In the US, Magellan maintains its working interests in oil and gas properties pursuant to leases from third parties. We have either commissioned title opinions or conducted title reviews on substantially all of our properties and believe we have title to them. Magellan obtains title opinions to a drill site prior to commencing initial drilling operations. In accordance with industry practice, we perform only minimal title review work at the time of acquiring undeveloped properties.

United Kingdom

In the UK, the petroleum licensing regime is administered by the UK Department of Energy and Climate Change ("DECC"), and PEDLs and Seaward Production Licenses (denoted by a "P") issued by the DECC are subject to the UK Petroleum Act of 1998. A licensee has the exclusive right to produce, explore, and develop petroleum from the land, subject to the payment of rental to the DECC. The maximum term of the license is 31 years. Licenses expire after the initial exploration term of 6 years if a well is not drilled and after a second exploration term of 5 years if a well is drilled but no development program is approved by the DECC. If a development program is approved by the DECC, a PEDL will convert into a production license with a term of approximately 20 years. The licensing regime also requires that 50% of the acreage of a PEDL be relinquished at the end of the initial exploration period. This 50% relinquishment is expected to be applicable to Magellan's licenses upon their respective initial expiration dates.

With respect to the PEDLs 231, 234, and 243, the Company and its partner, Celtique, negotiated with DECC an amendment to the terms of exploration, whereby the expiration date of the initial exploration term was extended by two years to June 2016, with the expiration date of the second exploration term remaining unchanged. As a result, in the case of these PEDLs, the second exploration term will only last three years.

With respect to PEDLs 137 and 246, the Company and its partners negotiated with DECC an amendment to the terms of exploration, whereby for PEDL 137, the expiration of the second exploration term was extended to September 30, 2016, and for PEDL 246, the expiration of the initial exploration term was extended to June 30, 2016, and the expiration of the second exploration term was extended to June 30, 2019.

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The following table summarizes the permits we maintain in the UK as of June 30, 2015.

License	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres (1)	Net acres (2)
Central Weald licenses:						
PEDL 231	Weald	6/30/2016	Celtique [3]	50%	98,800	49,400
PEDL 234	Weald	6/30/2016	Celtique [3]	50%	74,100	37,050
PEDL 243	Weald	6/30/2016	Celtique [3]	50%	74,100	37,050
Subtotal					247,000	123,500
Licenses containing Horse Hill-1:						
PEDL 137	Weald	9/30/2016	HHDL	35%	24,525	8,584
PEDL 246	Weald	6/30/2019	HHDL	35%	10,769	3,769
Subtotal					35,294	12,353
Other licenses on periphery of Weald Basin:						
P1916	Wessex	1/31/2017	UKOG	22.5%	11,535	2,595
Total					293,829	138,448

(1) A gross acre is an acre in which the registrant owns a working interest.
(2) The number of net acres is the sum of the fractional working interests owned by the registrant in gross acres.
(3) See Note 14 - Commitments and Contingencies - Celtique Litigation, of the Notes to Consolidated Financial Statements included in this report for information regarding a currently pending legal proceeding initiated by Celtique with respect to this license.

Australia

In Australia, Magellan's offshore exploration license, NT/P82, is issued jointly by the Commonwealth and Northern Territory Governments and is subject to the Offshore Petroleum and Greenhouse Gas Storage Act. The licensee has the exclusive right to explore for petroleum in the license area, subject to fulfillment of a pre-agreed work program. The term of a petroleum license is 6 years, and a license may be renewed for a further term of 5 years.

The following table summarizes the permit we maintain in Australia as of June 30, 2015.

License	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres [1]	Net acres [2]
NT/P82	Bonaparte	5/12/2016	Magellan	100%	1,566,647	1,566,647
Total					1,566,647	1,566,647

(1) A gross acre is an acre in which the registrant owns a working interest.
(2) The number of net acres is the sum of the fractional working interests owned by the registrant in gross acres.

MARKETING ACTIVITIES AND CUSTOMERS

Customers

The Company's oil production revenue is derived from its NP segment and was generated from two customers for the year ended June 30, 2015, and a single customer for the year ended June 30, 2014.

Delivery Commitments

None of our production sales agreements contain terms and conditions requiring us to deliver a fixed determinable quantity of product.

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CURRENT MARKET CONDITIONS AND COMPETITION

Seasonality of Business

Demand and prices for oil and gas can be impacted by seasonal factors. Increased demand for heating oil in the winter and gasoline during the summer driving season can positively impact the price of oil during those times. Increased demand for heating during the winter and air conditioning during the summer months can positively impact the price of natural gas. Unusual weather patterns can increase or dampen normal price levels. Our ability to carry out drilling activities can be adversely affected by weather conditions during winter months at Poplar. In general, the Company's working capital balances are not materially impacted by seasonal factors.

Competitive Conditions in the Business

The oil and gas industry is highly competitive. We face competition from numerous major and independent oil and gas companies, many of whom have greater technical, operational, and financial resources, or who have vertically integrated operations in areas such as pipelines and refining. Our ability to compete in this industry depends upon such factors as our ability to identify and economically acquire prospective oil and gas properties; the geological, geophysical, and engineering capabilities of management; the financial position and resources of the Company; and our ability to secure drilling rigs and other oil field services in a timely and cost-effective manner. We believe our acreage positions, our management's technical and operational expertise, and our limited long-term debt allow us to effectively compete in the exploration and development of oil and gas projects.

The oil and gas industry itself faces competition from alternative fuel sources, which include other fossil fuels, such as coal and renewable energy sources.

EMPLOYEES AND OFFICE SPACE

As of June 30, 2015, the Company had a total of 20 full-time employees, including 8 employees in the field at Poplar. We maintain approximately 6,000 square feet of functional office space in Denver, Colorado for our executive and administrative headquarters.

GOVERNMENT REGULATIONS

Our business is extensively regulated by numerous foreign, US federal, state, and local laws and governmental regulations. These laws and regulations may be changed from time to time in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential of increasing our cost of doing business and, consequently, could affect our results of operations. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

US Energy Regulations

States in which we operate have adopted laws and regulations governing the exploration for, and production of, oil and gas, including laws and regulations that (i) require permits for the drilling of wells; (ii) impose bonding requirements in order to drill or operate wells; and (iii) govern the timing of drilling and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Many of our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, state conservation laws sometimes establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM") and/or the Bureau of Indian Affairs ("BIA"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders that are subject to change. In addition to permits required from other regulatory agencies, lessees, such as Magellan, must obtain a permit from the BLM before drilling and must comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure

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that lessee obligations are met. Under certain circumstances, the BLM or the BIA may suspend or terminate our operations on federal or Indian leases.

In May 2010, the BLM adopted changes to its oil and gas leasing program that require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes have increased the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

The sale of natural gas in the US is affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce. FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of natural gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect sales prices for natural gas production. In addition, the less stringent regulatory approach currently pursued by FERC and the US Congress may not continue indefinitely.

Environmental, Health, and Safety Matters

General. Our operations are subject to stringent and complex federal, state, tribal, and local laws and regulations governing protection of the environment and worker health and safety as well as the discharge of materials into the environment. These laws, rules, and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules, and regulations may also restrict our ability to produce oil or gas to a rate of oil and natural gas production that is lower than the rate that is otherwise possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly permitting, waste handling, disposal, and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules, and regulations to which our business is subject:

Waste handling. The Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of the RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under the RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations, financial condition, and cash flows.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the US and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, US Army Corps of Engineers, or analogous state agencies. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 ("OPA") addresses prevention, containment and cleanup, and liability associated with oil pollution. The OPA applies to vessels, offshore platforms, and onshore facilities, and subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

Air emissions. The federal Clean Air Act ("CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on this determination, the EPA has been adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. See Item 1A, Risk Factors - Risks Related to Our Business - Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil and natural gas. In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent and more intensive storms and flooding, and could adversely affect the demand for oil and natural gas.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our well drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts on protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to achieve timely well drilling and development and could adversely affect our future production from those areas.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal and Indian lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect, and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal and Indian lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay development of some of our oil and natural gas projects.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

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Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. While we have not routinely utilized hydraulic fracturing techniques in our drilling and completion programs in the past, we may do so in the future in connection with our potential unconventional development with Celtique in southern England, or if we expand our Bakken/Three Forks play at Poplar. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions, and in the UK an Office of Unconventional Gas and Oil has been established to coordinate the related activities of various regulatory authorities. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program. The federal Safe Drinking Water Act protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques, which could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs, and delays, all of which could adversely affect our financial position, results of operations, and cash flows. For example, the UK government imposed a temporary moratorium on hydraulic fracturing in the UK that was lifted in December 2012. In addition, local planning permission requirements in the UK may have the effect of restricting or delaying hydraulic fracturing activities. The UK Infrastructure Act 2015 seeks to include safeguards around hydraullic fracturing, and draft regulations issued in the UK in July 2015, are intended to define protected areas in which hydraulic fracturing will be prohibited. If new laws, rules, regulations, or other requirements that significantly restrict hydraulic fracturing are adopted, such requirements could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes more strictly regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, or becomes subject to regulatory restrictions at the local level, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Other initiatives. Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement initiatives being either proposed or implemented. For example, the EPA's 2014 - 2016 National Enforcement Initiatives include "Assuring Energy Extraction Sector Compliance with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that this initiative will be focused on those areas of the US where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve an investigation of our facilities and processes, and could lead to potential enforcement actions, penalties, or injunctive relief against us. In addition, in August 2015, the EPA released proposed regulations that would set performance standards for emissions of methane and volatile organic compounds from new and modified sources in the upstream and midstream oil and gas sectors.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot give any assurance that we will not be adversely affected in the future.

Regulations Applicable to Foreign Operations

Several of the properties and investments in which we have interests are located outside of the US, and are subject to foreign laws, regulations, and related risks involved in the ownership, development, and operation of foreign property interests. Foreign laws and regulations may result in possible nationalization of assets, expropriation of assets, confiscatory taxation, changes in foreign exchange controls, currency revaluations, price controls or excessive royalties, export sales restrictions, and limitations on the transfer of interests in exploration licenses. Foreign laws and regulations may also limit our ability to transfer funds or proceeds from operations or investments. In addition, foreign laws and regulations providing for conservation, proration, curtailment, cessation, or other limitations or controls on the production of or exploration for hydrocarbons may increase the costs or have other adverse effects on our foreign operations or investments. As a result, an investment in us is subject to foreign legal and regulatory risks in addition to those risks inherent in US domestic oil and gas exploration and production company investments.

Oil and gas exploration and production operations in the UK are subject to numerous UK and European Union ("EU") laws and regulations relating to environmental matters, health, and safety. Environmental matters are addressed before oil and gas production activities commence and during the exploration and production activities. Before a UK licensing round begins,

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the DECC will consult with various public bodies that have responsibility for the environment. Applicants for production licenses are required to submit a summary of their management systems and how those systems will be applied to the proposed work program. In addition, the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 require the Secretary of State to exercise the Secretary's licensing powers under the UK Petroleum Act in such a way as to ensure that an environmental assessment is undertaken and considered before consent is given to certain projects. Further, depending on the scale of operations, production facilities may be subject to compliance obligations under the EU emissions trading system. Compliance with the above regulations may cause us to incur additional costs with respect to UK operations.

Our Australian investments and prospects are subject to stringent Australian laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations, which include the Environment Protection and Biodiversity Conservation Act 1999, require approval before seismic acquisition or drilling commences, restrict the types, quantities, and concentration of substances that can be released into the environment in connection with drilling and production activities, limit or prohibit seismic or drilling activities in protected areas, and impose substantial liabilities for pollution resulting from oil and gas operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Changes in Australian environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal, or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position, investment values, or financial condition as well. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release of such materials or if our operations were standard in the industry at the time they were performed.

AVAILABLE INFORMATION

Our internet website address is www.magellanpetroleum.com. We routinely post important information for investors on our website, including updates about us and our operations. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. We also make available within our website's corporate governance section the by-laws, code of conduct, and charters for the Audit Committee and the Compensation, Nominating and Governance Committee of the Board of Directors of Magellan. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATION

Adjusted EBITDAX

We define Adjusted EBITDAX as net (loss) income, plus (minus): (i) depletion, depreciation, amortization, and accretion expense, (ii) exploration expense, (iii) stock based compensation expense, (iv) foreign transaction loss, (v) impairment expense, (vi) loss on investment in securities and sale of assets (vii) net interest expense and amortization of loan fees, (viii) (fair value revision of contingent consideration payable), (ix) other (income), and (x) net (income) from discontinued operations. Adjusted EBITDAX is not a measure of net income or cash flow as determined by GAAP and excludes certain items that we believe affect the comparability of operating results.

Our Adjusted EBITDAX measure provides additional information that may be used to better understand our operations. Adjusted EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net (loss) income as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as the historic cost of depreciable and depletable assets. Adjusted EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, Adjusted EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure and to assess the financial performance of our assets and our company without regard to historical cost basis and certain items that affect the comparability of period to period operating results.

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The following table provides a reconciliation of net income (loss) to Adjusted EBITDAX for the fiscal years ended:

	June 30,	
	2015	2014
	(In thousands)	
Net (loss) income	$(43,411)	$15,509
Depletion, depreciation, amortization, and accretion expense	1,149	1,123
Exploration expense	1,563	3,484
Stock based compensation expense	891	2,009
Foreign transaction loss	635	165
Impairment of proved oil and gas properties	17,353	—
Impairment of goodwill	674	—
Loss on investment in securities	15,087	—
Loss on sale of assets	316	
Net interest expense	83	233
Amortization of loan fees	100	10
Fair value revision of contingent consideration payable	(1,888)	(2,403)
Other income	(267)	(146)
Net income from discontinued operations	—	(25,551)
Adjusted EBITDAX	$(7,715)	$(5,567)

For clarification purposes, the following table provides an alternative method for calculating Adjusted EBITDAX, which can also be calculated as revenue less (i) lease operating expense and (ii) general and administrative expense; plus (i) stock based compensation expense and (ii) foreign transaction loss.

The following table provides the alternative method for calculating Adjusted EBITDAX for the fiscal years ended:

	June 30,	
	2015	2014
	(In thousands)	
Total revenues	$4,459	$7,601
Less:		
Lease operating	(5,089)	(6,257)
General and administrative	(8,611)	(9,085)
Plus:		
Stock based compensation expense	891	2,009
Foreign transaction loss	635	165
Adjusted EBITDAX	$(7,715)	$(5,567)

ITEM 1A: RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in us. These risk factors and other uncertainties may cause our actual future results or performance to differ materially from any future results or performance expressed or implied in the forward-looking statements contained in this report and in other public statements we make. In addition, because of these risks and uncertainties, as well as other variables affecting our operating results, our past financial performance is not necessarily indicative of future performance.

RISKS RELATING TO OUR BUSINESS

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

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We incurred losses from operations for the fiscal year ended June 30, 2015 of $43.4 million. In addition, working capital decreased from $25.6 million at June 30, 2014 to $3.9 million at June 30, 2015. We continue to experience decreased liquidity as a result of the recent decline in oil and gas commodity prices and other factors discussed below. Consequently, we have begun selling some non-core assets to fund our operations. However, proceeds from these asset sales may not provide sufficient liquidity to fund operations for the next twelve months. These factors raise substantial doubt about our ability to continue as a going concern. The consolidated financial statements included in this report do not include any adjustments relating to the recoverability and classification of recorded asset amounts or amounts of liabilities that might result from the outcome of this uncertainty.

Our current liquidity position is very constrained.
During the twelve months ended June 30, 2015, we used $15.4 million in cash and, as of June 30, 2015, we had $1.1 million in cash and cash equivalents. The decline in cash and cash equivalents is primarily the result of the cost of injecting CO_2 in and managing the pilot program at Poplar, the loss from operations at Poplar due to the decrease in oil prices, and our general and administrative expenses. As of October 9, 2015, our cash balances amounted to approximately $620 thousand, and we currently have a monthly cash burn rate ranging between $500 thousand and $750 thousand. Accordingly, we are facing significant liquidity constraints in the short term, and there is a substantial risk that we will not be able to fund our activities on an ongoing basis. Although we have been implementing some cost savings initiatives and are working on alternatives to fund our activities, there is no assurance that those initiatives and alternatives will be successful. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Consolidated Liquidity and Capital Resources" included in this report.

A legal proceeding initiated by Celtique may have a material adverse effect on our interests in the central Weald Basin of the UK.
In the central Weald Basin of the UK, we co-own equally with Celtique three licenses, PEDLs 231, 234, and 243, representing 124 thousand net acres that may be prospective for oil and gas development. During the second quarter of the fiscal year ended June 30, 2015, we received a cash call from Celtique for the advancement of estimated expenses in the amount of $2.0 million in connection with the Broadford Bridge-1 well, the site for which is located within the PEDL 234 license area, and we are evaluating our alternatives under the applicable joint operating agreement. During the third quarter of the fiscal year ended June 30, 2015, Celtique initiated a legal proceeding against us with respect to that cash call and related issues. See Note 14 - Commitments and Contingencies - Celtique Litigation of the Notes to Consolidated Financial Statements included in this report for further information. We cannot predict the ultimate outcome of this matter, which may have a material adverse effect on our interests in the central Weald licenses and/or require the payment of amounts for which we would need to obtain funding.

Oil prices have decreased substantially from historic highs and may remain depressed for the foreseeable future. Any additional decreases in prices of oil may materially and adversely affect our cash generated from operations, results of operations, financial position, our ability to repay our debt, and the trading price of our common stock.
Since the second half of 2014, oil prices have declined significantly. After averaging $101.05 per barrel in the first half of calendar 2014, West Texas Intermediate ("WTI") oil prices averaged $85.54 per barrel for the second half of calendar 2014, declined to $59.48 per barrel on June 30, 2015, and were $49.63 per barrel on October 9, 2015. As a result of the decrease in oil prices, we incurred an impairment of oil and gas properties of $17.4 million during the fiscal year ended June 30, 2015. In addition, as a result of similarly decreased oil and natural gas prices in Australia, we incurred a loss on the sale of securities and an other-than-temporary impairment on an investment in securities totaling $15.1 million during the fiscal year ended June 30, 2015, which was largely attributable to an unrealized loss on our investment in the securities of Central. We may incur additional impairments of our oil and gas properties and losses on our investment in securities if prices do not increase. The possibility and amounts of any future impairments or losses are difficult to predict, and will depend, in part, upon future oil and natural gas prices. The International Energy Agency forecasts continued U.S. production growth and a slowdown in global demand growth in 2015. This

environment could cause the prices for oil to remain at current levels or to fall to lower levels. If prices for oil continue to remain depressed for lengthy periods, we may be required to write down the value of our oil and gas properties, and some of our current projects may no longer be economically viable. In addition, sustained low prices for oil will negatively impact the value of our estimated proved reserves and reduce the amounts of cash we would otherwise have available to pay expenses and service our indebtedness.

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Our CO_2-EOR project at Poplar may not be successful.
In August 2013, we initiated a five-well CO_2-EOR pilot program for the Charles formation at the Poplar field to enhance oil recovery through the injection of CO_2 into the formation. All five wells have been drilled to total depth, and we have conducted the initial CO_2 injection phase of the program. Through June 30, 2015, we had incurred approximately $27.3 million in capitalized costs in connection with the pilot program, and we currently believe that costs related to the pilot program, including capital and certain operating expenditures, will be limited to i) the ongoing costs of operating the five wells, which form the CO_2-EOR pilot and ii) the cost of purchasing CO_2, to the extent the company decides to resume the injection of CO_2 in the CO_2-EOR pilot. While laboratory analysis and other tests indicate that a CO_2-EOR project at Poplar should be technically and economically viable on a full-field and long-term basis, the additional production and reserves that may result from CO_2-EOR methods are inherently difficult to predict. For example, although CO_2 may be successfully injected through an injector well and initially result in satisfactory increased pressures, it is possible that such pressures may not be sustained at sufficient effective levels to sweep the oil across the formation to the production wells. If CO_2-EOR methods at Poplar ultimately do not allow for the extraction of additional oil in the manner or to the extent that we anticipate, our future results of operations, cash flows, and financial condition could be materially adversely affected. In addition, our ability to utilize CO_2 as an enhanced recovery technique is subject to the ability to obtain sufficient quantities of CO_2. Although we currently have a short-term CO_2 supply agreement for the pilot program, if the quantities of CO_2 available to Poplar become limited, there may not be sufficient CO_2 to produce oil in the manner or to the extent that we anticipate, and our future oil production volumes could be negatively impacted.

Substantially all of our currently producing properties are located in the Poplar field, making us vulnerable to risks associated with having revenue-producing operations currently concentrated in one geographic area.
Because our current revenue-producing operations are geographically concentrated in the Poplar field in the Montana portion of the Williston Basin, the success and profitability of our operations are disproportionately exposed to risks associated with regional factors. These include, among others, fluctuations in the prices of crude oil and natural gas produced from wells in the region, other regional supply and demand factors, including gathering, pipeline, and rail transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor, and infrastructure capacity, and the effects of regional or local governmental regulations. In addition, our operations at Poplar may be adversely affected by seasonal weather and wildlife protection measures, which can intensify competition for the items described above during months when drilling is possible and may result in periodic shortages. The concentration of our operations in this region also increases exposure to unexpected events that may occur in this region such as natural disasters or labor difficulties. Any one of these events has the potential to cause a relatively significant number of our producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs, and prevent development or production within originally anticipated time frames. Any of the risks described above could have a material adverse effect on our financial condition, results of operations, and cash flows.

Our Poplar production revenues and cash flows are concentrated with one purchaser, and that purchaser may reduce or discontinue purchases or become unable to meet its payment obligations to us.
Sales of our Poplar oil production are currently concentrated with an agreement with Plains Marketing, LP, who is the sole purchaser of our oil production at Poplar. If this purchaser reduces or discontinues purchases from us, or if we are unable to successfully negotiate a replacement agreement with this purchaser, who can terminate the agreement after a 90-day notice period, or if the replacement agreement has less favorable terms, the effect on us could be materially adverse if we are unable to obtain new purchasers for the oil produced at Poplar. In addition, if this purchaser were to experience financial difficulties or any deterioration in its ability to satisfy its payment obligations to us, our revenues and cash flows from Poplar could be adversely affected to a material extent.

Regulations related to hydraulic fracturing could result in increased costs and operating restrictions or delays that could affect the value of our potential unconventional play in the United Kingdom.

We along with Celtique currently have a 50%-50% working interest in a potential unconventional play in the central Weald Basin in southern England that is operated by Celtique. Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including unconventional gas resources. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Although the UK government lifted a temporary moratorium on hydraulic

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fracturing in December 2012 and an Office of Unconventional Gas and Oil has been established in the UK to coordinate the related activities of various regulatory authorities, hydraulic fracturing remains a publicly controversial topic, with media and local community concerns regarding the use of fracturing fluids, impacts on drinking water supplies, and the potential for impacts to surface water, groundwater, and the environment generally. For example, local planning permission requirements in the UK may have the effect of restricting or delaying drilling activities in general or hydraulic fracturing in particular. If hydraulic fracturing is significantly restricted or delayed at our potential unconventional play in the UK, or made more costly, the volumes of natural gas that can be economically recovered could be reduced, which would adversely affect the value of the play.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our Australian NT/P82 prospect and other exploration and development activities.
We have incurred significant expenditures to acquire extensive 2-D and 3-D seismic data with respect to our NT/P82 exploration permit area in the Bonaparte Basin, offshore Northern Territory, Australia, and we use 2-D and 3-D seismic data in our other exploration and development activities. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators, and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We may not be successful in sharing the exploration and development costs of the fields, licenses, and permits in which we hold interests, such as our Australian NT/P82 prospect.
Our current drilling plans depend, in certain cases, on our ability to enter into farm-in, farmout, joint venture, or other cost sharing arrangements with other oil and gas companies. For example, we are engaged in a farmout process for our NT/P82 exploration permit area, in which we plan to relinquish a portion of our working interest in, and operatorship of, NT/P82 in exchange for a commitment from the partner to drill exploration wells over the gas prospects identified in the block to meet our requirements under the terms of the permit. If we are not able to secure such farm-in, farmout, or other arrangements in a timely manner, or on terms which are economically attractive to us, we may be forced to bear higher exploration and development costs with respect to our fields and interests. We may also be unable to fully develop and/or explore certain fields if the costs to do so would exceed our available liquidity and capital resources. In either case, our results of operations, financial condition, and cash flows could be adversely affected and the market price of our common stock could decline.

We may not realize the expected value and potential liquidity from our significant investment in Central Petroleum Limited.
On March 31, 2014, we sold our non-core assets in the Amadeus Basin of Australia to Central Petroleum Limited, in exchange for AUD $20.0 million in cash and 39.5 million shares of Central's stock, which are listed for trading on the Australian Securities Exchange ("ASX") and which represented an approximately 11% equity ownership interest in Central. Under the terms of the agreement for that transaction, the Central shares were valued at AUD $15.0 million. As of June 30, 2015, the Central shares were carried on our balance sheet at a fair value of $4.2 million, based on the closing per share market price for Central stock as reported on the ASX on that date and applicable foreign currency translation adjustments.
Central is a Brisbane, Australia based junior exploration and production company that operates one of the largest holdings of prospective onshore acreage in Australia. Accordingly, Central and the value of its stock are subject to similar business, industry, and oil and natural gas price fluctuation risk factors that we are subject to, as well as Central's own particular risk factors based on its current circumstances and operating areas in Australia. As a result, or for other reasons, the market price of Central stock may experience significant fluctuations, including significant decreases. We do not control Central, and our investment is subject to the risk that Central may make business,

financial, or management decisions with which we do not agree. Although the shares of Central that we hold are not restricted and may be sold on the ASX, the average daily trading volumes for Central stock relative to the number of Central shares that we hold may mean that our Central shares would need to be sold over a substantial period of time, exposing our investment return to risks of downward movement in the market price during the intended disposition period. Accordingly, we may ultimately realize a lower value and potential liquidity from our investment in Central than we expect.

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Exploration and development drilling may not result in commercially producible reserves.

Crude oil and natural gas drilling and production activities are subject to numerous risks, including the risk that no commercially producible crude oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and crude oil or natural gas drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we intend to drill;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, equipment, pipe, water, and other supplies.

The prevailing prices for crude oil and natural gas affect the cost of, and demand for, drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. In addition, general and industry economic and financial downturns can adversely affect the financial condition of some drilling contractors, which may constrain the availability of drilling services in some areas.

Another significant risk inherent in drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased or licensed properties within the applicable lease or license periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop the properties we have or may acquire.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if crude oil or natural gas is present, or whether it can be produced economically. The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling and completion costs.

Our future drilling activities may not be successful. Although we have identified potential drilling locations, we may not be able to economically produce oil or natural gas from them.

The loss of key personnel could adversely affect our ability to operate.

We depend, and will continue to depend in the foreseeable future, on the services of our executive management team and other key personnel. The ability to retain officers and key employees is important to our success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business. Our drilling success and the success of other activities integral to our operations depends, in part, on our ability to attract and retain experienced geologists, engineers, landmen, and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

We have limited management and staff and are dependent upon partnering arrangements.

We had 20 total employees as of June 30, 2015. Due to our limited number of employees, we expect that we will continue to require the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental, and tax services. We also plan to pursue alliances with partners in the areas of geological and geophysical services and prospect generation, evaluation, and prospect leasing. Our dependence on third party consultants and service providers creates a number of risks, including but not limited to:

- the possibility that such third parties may not be available to us as and when needed; and

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- the risk that we may not be able to properly control the timing and quality of work conducted with respect to our projects.

If we experience significant delays in obtaining the services of such third parties or poor performance by such parties, our results of operations may be materially adversely affected.

There are risks inherent in foreign operations and investments, such as adverse changes in currency values and foreign regulations relating to MPUK's, MPA's, and Central's exploration and development operations, and potential taxes or restrictions on dividends to MPC from foreign subsidiaries or investments.

The properties in which we have operating or investment interests that are located outside the US are subject to certain risks related to the indirect ownership and development of, or investment in, foreign properties, including government expropriation and nationalization, adverse changes in currency values and foreign exchange controls, foreign taxes, US taxes on the repatriation of funds to the US, and other laws and regulations, any of which may have a material adverse effect on our properties, investments, financial condition, results of operations, or cash flows. Although there are currently no foreign exchange controls on the payment of dividends to MPC by its subsidiaries or other entities in which it has invested, such payments could be restricted by foreign exchange controls, if implemented.

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

Our revenues, results of operations, future rate of growth, and the carrying value of our oil and gas properties depend heavily on the prices we receive for the crude oil and natural gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The markets for crude oil and natural gas have historically been, and are likely to continue to be, volatile and subject to wide fluctuations in response to numerous factors, including the following:

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

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty, but in general we expect oil and gas prices to continue to fluctuate significantly. Further and sustained declines in oil and gas prices would not only reduce our revenues but also could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows, and reserves. Further, oil and gas prices do not necessarily move in tandem. Future oil and gas sales would generate lower revenue if oil and natural gas prices were to continue to decline. Prices for sales of our oil production are primarily affected by global oil prices, and the volatility of those prices will affect future oil revenues.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technical, and other resources than we do.

We face intense competition from major oil and gas companies and independent oil and gas exploration and production companies who seek oil and gas investments throughout the world, as well as the equipment, expertise, labor, and materials required to explore, develop, and operate crude oil and natural gas properties. Many of our competitors have financial, technical, and other resources vastly exceeding those available to us, and many crude oil and natural gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for the properties. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring, exploring, and developing profitable properties in the face of this competition.

We also compete for human resources. Over the last several years, the need for talented people across all disciplines in the industry has grown, while the number of talented people available has not grown at the same pace, and in many cases, is declining due to the demographics of the industry.

Our acquisitions of or investments in new oil and gas properties or other assets may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property or other acquisitions or investments require an assessment of a number of factors sometimes beyond our control. These factors include exploration potential, future crude oil and natural gas prices, operating costs, and potential environmental and other liabilities. These assessments are not precise, and their accuracy is inherently uncertain.

In connection with our acquisitions or investments, we typically perform a customary review of the properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests or otherwise invest in properties on an "as is" basis with limited remedies for breaches of representations and warranties.

In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.

Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.

These factors could have a material adverse effect on our business, financial condition, results of operations, and cash flows. Consideration paid for any future acquisitions or investments could include our stock or require that we incur additional debt and contingent liabilities. As a result, future acquisitions or investments could cause dilution of existing equity interests and earnings per share.

Our operations are subject to complex laws and regulations, including environmental laws and regulations that result in substantial costs and other risks.

US federal, state, tribal, and local authorities, and corresponding UK and Australian governmental authorities, extensively regulate the oil and natural gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing or marketing of crude oil and natural gas production. Noncompliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations, and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of crude oil and natural gas, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in crude oil and natural gas properties, rights-of-way and easements, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, and restoration standards, and oil and gas operations. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Governmental authorities also may require any of our ongoing or planned operations on their leases or licenses to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a material adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, tribal, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between various regulatory agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several liability or strict liability under federal, state, and tribal environmental laws for noise emissions and for discharges of crude oil, natural gas, and associated liquids or other pollutants into the air, soil, surface water, or groundwater. We could be required to spend substantial amounts on investigations, litigation, and remediation for these discharges and other compliance issues. Any unpermitted release of petroleum or other pollutants from our operations could result not only in cleanup costs but also natural resources, real or personal property, and other compensatory damages and civil and criminal liability. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a material adverse effect on us.

In addition, we may be subject to increased environmental law enforcement initiatives. For example, the EPA's current National Enforcement Initiatives include "Ensuring Energy Extraction Activities Comply with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." This initiative could involve an investigation of our facilities and processes, and could lead to potential enforcement actions, penalties, or injunctive relief against us.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil and natural gas.

Due to concerns about the risks of global warming and climate change, a number of various national and regional legislative and regulatory initiatives to limit greenhouse gas emissions are currently in various stages of discussion or implementation. For example, the US Environmental Protection Agency has been adopting and implementing various rules regulating greenhouse gas emissions under the US Clean Air Act, the US Congress has from time to time considered other legislative initiatives to reduce emissions of greenhouse gases, and many states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas emission allowance cap and trade programs. In addition, in 2013, the US President announced a Climate Action Plan which, among other things, directs US federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas industry. In November 2014, the US President announced that the US would seek to cut net greenhouse gas emissions 26% to 28% below 2005 levels by 2025 in return for China's commitment to seek to peak emissions around 2030, with concurrent increases in renewable energy.

Legislative and regulatory programs to reduce emissions of greenhouse gases could require us to incur substantially increased capital, operating, maintenance, and compliance costs, such as costs to purchase and operate emissions control systems, costs to acquire emissions allowances, and costs to comply with new regulatory or reporting requirements. Any such legislative or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislative and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition, results of operations, and cash flows.

In addition, there has been public discussion that climate change may be associated with more extreme weather conditions, such as increased frequency and severity of storms, droughts, and floods. Extreme weather conditions can interfere with our development and production activities, increase our costs of operations or reduce the efficiency of our operations, and potentially increase costs for insurance coverage in the aftermath of such conditions. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies, or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses, or costs that may result from potential physical effects of climate change.

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Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

This report contains estimates of our proved and probable reserves and the estimated future net revenues from our proved reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. The process of estimating oil and gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and gas reserves will most likely vary from these estimates. Any significant variation of any nature could materially affect the estimated quantities and present value of our proved reserves, and the actual quantities and present value may be significantly less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production by operators on adjacent properties. Probable reserves are less certain to be recovered than proved reserves.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on the average, first-day-of-the-month price during the 12-month period preceding the measurement date, in accordance with SEC rules. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual costs of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation, including severance and excise taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor required by the SEC to be used to calculate discounted future net cash flows for reporting purposes may not be the most appropriate discount factor in view of actual interest rates, costs of capital, and other risks to which our business or the oil and natural gas industry in general are subject.

SEC rules could limit our ability to book proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit in the future our ability to book proved undeveloped reserves as we pursue drilling programs on our undeveloped properties. In addition, we may be required to write down any booked proved undeveloped reserves if we do not drill the scheduled wells within the required five-year timeframe.

Substantial capital is required for our business and projects.

Our exploration, development, and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, farming-in other companies or investors to our exploration and development projects in which we have an interest, sales of non-core assets, and/or debt or equity financings. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices for oil and natural gas, and our success in developing and producing new reserves. If revenues decrease as a result of lower oil or natural gas prices or decreased production, and our access to capital continues to be limited, we will have a reduced ability to explore and develop our properties and replace our reserves. If our cash flows from operations are not sufficient to fund our planned capital expenditures, we must reduce our capital expenditures unless we can raise additional capital through debt, equity, or other financings or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be of acceptable value to us.

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If we are not able to replace reserves, we will not be able to sustain production.

Our future success depends largely upon our ability to find, develop, or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful exploration, development, or acquisition activities, our reserves will decline over time. Recovery of any additional reserves will require significant capital expenditures and successful drilling operations. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved or probable reserves at acceptable costs.

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

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

The capitalized costs of our oil and natural gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each depletion pool to the estimated fair value (discounted future net cash flows of that depletion pool). For example, in the fiscal year ended June 30, 2015, as a result of significant declines in oil commodity prices, we incurred an impairment loss of $17.4 million on our proved oil and gas properties. A further significant decline in oil or natural gas prices from current levels, or other factors, could cause a further impairment write-down of capitalized costs and a non-cash charge against future earnings. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date, even if oil or natural gas prices increase.

Oil and gas drilling and production operations are hazardous and expose us to environmental liabilities.

Oil and gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine, or well fluids, and other environmental hazards and risks. Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings, and separated cables. If any of these or similar events occur, we could sustain substantial losses as a result of:

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

Our liability for environmental hazards may include those created either by the previous owners of properties that we purchase, lease, or license, or by acquired companies prior to the date we acquire them. We maintain insurance against some, but not all, of the risks described above. Our insurance may not be adequate to cover casualty losses or liabilities, and in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

In recent years, the US, UK, Australian, and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, increased levels of unemployment, and an unprecedented level of government intervention. Although some portions of the economy appear to have stabilized and may be recovering, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Renewed weakness in the US, UK, Australian, or other large economies could materially adversely affect our business, financial condition, results of operations, and cash flows. For example, purchasers of our oil and gas production may reduce the amounts of oil and gas they purchase from us and/or delay or be unable to make timely payments to us.

In addition, some of our oil and gas properties are operated by third parties that we depend on for timely performance of drilling and other contractual obligations and, in some cases, for distribution to us of our proportionate share of revenues from sales of oil and natural gas production. If weak economic conditions adversely impact our third party operators, we are exposed to the risk that drilling operations or revenue disbursements to us could be delayed or suspended.

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We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an ownership interest are operated by other companies. As a result, we have limited ability to exercise influence over, and control the risks associated with, the development and operation of those properties. The timing and success of drilling and development activities on those properties depend on a number of factors outside of our control, including the operator's:

- determination of the nature and timing of drilling and operational activities;
- determination of the timing and amount of capital expenditures;
- expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of suitable technology.

The failure of an operator of our properties to adequately perform development and operational activities, an operator's breach of the applicable agreements, or an operator's failure to act in ways that are in our best interests could reduce our production, revenues, and reserves, and have a material adverse effect on our financial condition, results of operations, and cash flows.

Currency exchange rate fluctuations may negatively affect our operating results.

The exchange rates between the US dollar and the British pound, as well as the exchange rates between the Australian dollar and the US dollar, have fluctuated in recent periods and may fluctuate substantially in the future. We expect that a majority of our revenues will be denominated in US dollars in the future. However, because of our UK development program, a portion of our expenses, including exploration costs and capital and operating expenditures, will continue to be denominated in British pounds. Accordingly, any material appreciation of the British pound against the US dollar could have a negative impact on our results of operations and financial condition. Our foreign exchange transaction loss for the fiscal year ended June 30, 2015, was $635 thousand and is included under general and administrative expenses in the consolidated statement of operations.

Proposed changes to US tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations, and cash flows.

The US President's budget proposals have included recommendations that would, if enacted, make significant changes to US tax laws applicable to oil and natural gas exploration and production companies, and legislation has been previously introduced in the US Congress that would implement many of these proposals. These proposed changes include, but are not limited to:

- eliminating the current deduction for intangible drilling and development costs;
- eliminating the deduction for certain US production activities for oil and natural gas production;
- repealing the percentage depletion allowance for oil and natural gas properties; and
- extending the amortization period for certain geological and geophysical expenditures.

These proposed changes in the US tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations, and cash flows.

One Stone has significant influence on our major corporate decisions, including veto power over some matters, and could take actions that could be adverse to other stockholders. In addition, One Stone has rights as a holder of preferred stock that are senior to, and could disadvantage, holders of our common stock.

In May 2013, we issued 19.2 million shares of Series A convertible preferred stock to an affiliate of One Stone for approximately $23.5 million. Additional shares of Series A preferred stock have since been issued to the One Stone affiliate in payment of preferred stock dividends, and the One Stone affiliate held a total of 21.2 million shares of Series A preferred stock as of June 30, 2015, which represents approximately 32% of our outstanding common stock on an as-converted basis. The certificate of designations governing the Series A preferred stock provides the holder of such stock with certain rights relating to our business and management, including the right to appoint a specified number of members of our board of directors (currently two); the right to vote on an as-converted basis with our common stockholders on matters submitted to a stockholder vote; the right to veto certain corporate actions, including some related party transactions and changes to our capital budget;

and the right to receive a cash payment providing it with a specified rate of return in the event of certain change of control transactions. As a result of the foregoing, One Stone has significant influence on our major corporate decisions, and matters requiring stockholder approval. The interests of One Stone may differ from the interests of our other stockholders in some circumstances, and the ability of One Stone to influence certain of our major corporate decisions may harm the market price of our common stock by delaying, deferring, or preventing transactions that are or are perceived to be in the best interest of other stockholders or by discouraging third-party investors. In addition, the Series A preferred stock is senior to our common stock in terms of the right to receive dividends and payments in the event of a liquidation. These preferences could disadvantage the holders of our common stock, and may make it more difficult for us to raise equity capital in the future.

Our interests in the United Kingdom are subject to licenses that could be forfeited if certain drilling requirements are not met.

We own certain interests in the UK that are subject to licenses issued by the Secretary of State for Energy and Climate Change under the UK Petroleum Act 1998. In order to retain the interests granted by the licenses, we are required to meet certain drilling requirements. If these drilling requirements are not met or waived, the interests granted by the licenses would be forfeited.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of changing demand for oil and natural gas may have a material adverse effect on our business, financial condition, results of operations, and cash flows.

RISKS RELATED TO OUR COMMON STOCK

The market price of our common stock may fluctuate significantly, which may result in losses for investors.

During the past several years, the stock markets in general and for oil and gas exploration and production companies in particular have experienced significant price and volume fluctuations that have often been unrelated or disproportionate to the operating results and asset values of the underlying companies. In addition, due to relatively low trading volumes for our common stock, the market price for our common stock may fluctuate significantly more than the markets as a whole. The market price of our common stock could fluctuate widely in response to a variety of factors, including factors beyond our control. These factors include:

- changes in crude oil or natural gas commodity prices;
- our quarterly or annual operating results;
- investment recommendations by securities analysts following our business or our industry;
- additions or departures of key personnel;
- changes in the business, earnings estimates, or market perceptions of comparable companies;
- changes in industry, general market, or regional or global economic conditions; and
- announcements of legislative or regulatory changes affecting our business or our industry.

Fluctuations in the market price of our common stock may be significant, and may result in declines in the market price and losses for investors.

We may issue a significant number of shares of common stock under outstanding stock options, future equity awards under our 2012 Omnibus Incentive Compensation Plan, and our outstanding Series A convertible preferred stock, and common stockholders may be adversely affected by the issuance and sale of those shares.

As of June 30, 2015, we had 1,032,334 stock options outstanding, as adjusted to reflect the one share for eight share reverse split of our common stock completed on July 10, 2015, of which 679,057 were fully vested and exercisable, and 21,162,697 shares of Series A convertible preferred stock outstanding. As of that date, there were 169,453 shares of common stock remaining available for future awards under our 2012 Omnibus Incentive Compensation Plan. If all of the 1,032,334 outstanding stock options, which have exercise prices ranging from $8.08 to $17.22 per share, are exercised, or the outstanding shares of Series A convertible preferred stock are converted, the shares of common stock issued would represent approximately 15% and 32%, respectively, of the outstanding common shares. Sales of those shares could adversely affect the market price of our common stock, even if our business is doing well.

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If our common stock is delisted from the NASDAQ Capital Market, its liquidity and value could be reduced.
In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market, the common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2). If the closing bid price of the common stock is below $1.00 for 30 consecutive trading days, which occurred in December 2014-January 2015, then the closing bid price of the common stock must be $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule, which occurred in July 2015, after we completed a one share for eight shares reverse split of our common stock on July 10, 2015. On October 9, 2015, the closing market price of our common stock was $0.70 per share. If our common stock is delisted from trading on the NASDAQ Capital Market, it may be eligible for trading on the OTCQB, but the delisting of our common stock from NASDAQ could adversely impact the liquidity and value of our common stock. In addition, the listing of our common stock on the NASDAQ Capital Market is one of the conditions to our ability to utilize the “at-the-market” (“ATM”) common stock financing facility that we implemented on December 24, 2014, and a delisting of our common stock from the NASDAQ Capital Market could impair our ability to utilize the ATM facility and related shelf registration statement that was declared effective on December 3, 2014.

The recent reverse stock split of our shares of common stock may decrease the market trading liquidity of the shares due to the reduced number of shares outstanding, and may potentially have an anti-takeover effect.

In July 2015, we effected a one-for-eight reverse stock split of our shares of common stock in order to increase the bid price to more than $1.00 per share and thus maintain the listing for our common stock on the NASDAQ Capital Market. Although the reverse stock split was intended to avoid decreased liquidity for the shares in the event of a delisting from the NASDAQ Capital Market, the liquidity of the shares may be adversely affected by the reverse stock split as a result of the reduced number of shares outstanding following the reverse stock split. In addition, the reverse stock split may have increased the number of stockholders who own odd lots (less than 100 shares) of our common stock, creating the potential for such stockholders to experience an increase in the cost of selling their shares and greater difficulty effecting such sales. Further, since the stockholder-approved reverse stock split was accomplished without a corresponding reduction in the number of shares authorized for issuance under our certificate of incorporation, the relative increase in the number of shares authorized for issuance could, under certain circumstances, have an anti-takeover effect by enabling the Board of Directors to issue additional shares of common stock in a transaction making it more difficult for a party to obtain control of us by tender offer or other means.

We do not intend to pay cash dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our common stockholders.
Subject to the satisfaction of the dividend rights of our Series A convertible preferred stock, which provide for a dividend equivalent of 7.0% per annum on the issue price plus any accumulated unpaid dividends, payable in the form of cash, in kind (in the form of additional shares of Series A preferred stock), or a combination thereof (at our option), we currently anticipate that we will retain future earnings, if any, to reduce our accumulated deficit and finance the growth and development of our business. The Series A preferred stock ranks senior to the common stock with respect to dividends and other rights, and we do not intend to pay cash dividends on our common stock in the foreseeable future. Any future determination as to the declaration and payment of cash dividends on our common stock will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects, and any other factors that our board determines to be relevant. As a result, only appreciation of the price of our common stock, which may not occur, will provide a return to our common stockholders.

Our largest stockholder beneficially owns a significant percentage of our common stock, and its interests may conflict with those of our other stockholders.

As of June 30, 2015, One Stone Holdings II LP owns 21,162,697 shares of our Series A convertible preferred stock, and thereby currently beneficially owns approximately 32% of our common stock, assuming full conversion of the Series A preferred stock. The Series A preferred stock is entitled to vote on an as-converted basis with the common stock. In addition, two individuals affiliated with One Stone serve on our six-member board of directors. As a result, One Stone is able to exercise significant influence over matters requiring stockholder approval, including the election of directors, changes to our organizational documents, and significant corporate transactions. Further, for so long as One Stone owns at least 10% of the fully diluted common stock, assuming full conversion of the Series A preferred stock, One Stone will hold veto rights with

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respect to capital expenditures greater than $15.0 million that are not provided for in the then-current annual budget, changes in our principal line of business, an increase in the size of our board to more than 12 members, and certain other matters.

The concentration of ownership and voting power with One Stone may make it more difficult for any other holder or group of holders of our common stock to be able to significantly influence the way we are managed or the direction of our business. The interests of One Stone with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings, and other corporate opportunities, and attempts to acquire us, may conflict with the interests of our other stockholders. This concentration of ownership may make it more difficult for another company to acquire us and for stockholders to receive any related takeover premium unless One Stone approves the acquisition.

Provisions in our charter documents and Delaware law make it more difficult to effect a change in control of our company, which could prevent stockholders from receiving a takeover premium on their investment.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various barriers to the ability of a third party to acquire control of us, even if a change of control would be attractive to our existing stockholders. In addition, our certificate of incorporation and by-laws contain several provisions that may make it more difficult for a third party to acquire control of us without the approval of our board of directors. These provisions may make it more difficult or expensive for a third party to acquire a majority of our outstanding common stock. Among other things, these provisions:

- authorize us to issue preferred stock that can be created and issued by the board of directors without prior stockholder approval, with rights senior to those of the common stock;
- classify our board of directors so that only some of our directors are elected each year;
- prohibit stockholders from calling special meetings of stockholders; and
- establish advance notice requirements for submitting nominations for election to the board of directors and for proposing matters that can be acted upon by stockholders at a meeting.

These provisions also may delay, prevent, or deter a merger, acquisition, tender offer, proxy contest, or other transaction that might otherwise result in our stockholders receiving a premium over the market price of their common stock.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

ITEM 3: LEGAL PROCEEDINGS

The information required by this Item is incorporated herein by reference to the information set forth under "Celtique Litigation" in Note 14 - Commitments and Contingencies of the Notes to Consolidated Financial Statements included in this report.

ITEM 4: MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

PRINCIPAL MARKET

Magellan's common stock is traded on the NASDAQ Capital Market under the symbol MPET. The below table presents the quarterly high and low intraday prices during the periods indicated, as adjusted for the one-for-eight reverse stock split approved by stockholders and completed on July 10, 2015.

Quarter ended	High	Low
June 30, 2015	$5.44	$2.00
March 31, 2015	$7.44	$4.08
December 31, 2014	$17.36	$6.24
September 30, 2014	$18.64	$13.36
June 30, 2014	$20.16	$11.20
March 31, 2014	$12.32	$8.16
December 31, 2013	$9.04	$8.08
September 30, 2013	$9.12	$7.92

HOLDERS

As of October 9, 2015, based on information received from the Company's stock transfer agent, the number of record holders of Magellan's common stock was approximately 440 and, the number of beneficial owners was approximately 5,850.

FREQUENCY AND AMOUNT OF DIVIDENDS

Magellan has never paid a cash dividend on its common stock. The Company does not intend to pay cash dividends on its common stock in the foreseeable future.

The payment of dividends on our common stock is subject to the rights of holders of our Series A Preferred Stock, which ranks senior to the common stock with respect to dividend rights. For additional information see Note 10 - Preferred Stock to the consolidated financial statements included in this Form 10-K.

UNREGISTERED SALES OF EQUITY SECURITIES DURING THE FOURTH QUARTER OF FISCAL 2015

Pursuant to the terms and conditions of the Certificate of Designations of Series A Preferred Stock dated May 17, 2013, as amended, on June 30, 2015, the Company issued 363,978 shares of its Series A Preferred Stock as quarterly PIK dividends with respect to the 20,798,719 shares of Series A Preferred Stock outstanding as of the record date of June 15, 2015. One Stone Holdings II LP, as the sole holder of Series A Preferred Stock, received all of these PIK shares. The shares of Series A Preferred Stock were issued pursuant to the private placement exemption from registration under Section 4(a)(2) of the U.S. Securities Act of 1933, as amended (the “Securities Act”). The facts relied upon to make such exemption available include that the private placement was with a single person that has represented that it is an "accredited investor" within the meaning of Rule 501 under the Securities Act, and the securities are restricted from transfer except pursuant to an effective registration statement under the Securities Act or an available exemption from such registration. Each share of Series A Preferred Stock is convertible at any time, at the holder's option, into shares of the Company's Common Stock, at a conversion price of $9.77586545 per common share, subject to customary anti-dilution provisions. For additional information regarding the Series A Preferred Stock, see Note 10 - Preferred Stock of the Notes to consolidated financial statements included in this report.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no purchases of the Company's common stock by the Company during fourth quarter of the fiscal year covered by this report. All share amounts listed in this section have been adjusted to reflect the effects of the one for eight reverse stock split of our common stock which was completed on July 10, 2015 and is further described below.

On July 1, 2015, upon the vesting of 12,500 shares of restricted stock previously granted to executives of the Company and pursuant to the tax withholding provisions of the Company's restricted stock award agreements, the Company withheld on a cashless basis 2,822 shares to settle withholding taxes. The withheld shares were immediately cancelled.

On October 10, 2014, the Company purchased 31,250 shares of its common stock from William H. Hastings, a former Company executive, pursuant to an Options and Stock Purchase Agreement. See Note 9 - Stock Based Compensation to the consolidated financial statements included in this report for further details.

On July 1, 2014, upon the vesting of 18,750 shares of restricted stock previously granted to executives of the Company and pursuant to the tax withholding provisions of the Company's restricted stock award agreements, the Company withheld on a cashless basis 5,981 shares to settle withholding taxes. The withheld shares were immediately cancelled.

On January 14, 2013, the Company repurchased 1,158,080 shares of its common stock through a Collateral Agreement. See Note 11 - Stockholders' Equity to the consolidated financial statements included in this report for further details.

On September 24, 2012, the Company announced that its Board of Directors had approved a stock repurchase program whereby the Company was authorized to repurchase up to a total value of $2.0 million in shares of its common stock. During November 2012, the Company repurchased 18,692 shares pursuant to this program. As of June 30, 2014, $1.9 million in value of shares of common stock remained authorized for repurchase under this program. This authorization superseded the prior plan announced on December 8, 2000, and expired on August 21, 2014, with no further repurchases of stock.

Reverse Stock Split

On July 10, 2015, the Company filed an amendment to its certificate of incorporation to effect a 1-for-8 reverse stock split of its common stock, effective July 10, 2015. All share and per share amounts relating to the common stock, stock options to purchase common stock, including the respective exercise prices of each such option, and the conversion ratio of the Series A Preferred Stock included within this report have been retroactively adjusted to reflect the reduced number of shares resulting from this action. Market conditions tied to stock price targets contained within MBOs were similarly adjusted. The par value and the number of authorized, but unissued, shares remain unchanged following the reverse stock split. No fractional shares were issued following the reverse stock split and the Company has paid cash in lieu of any fractional shares resulting from the reverse stock split.

ITEM 6: SELECTED FINANCIAL DATA

The Company is a smaller reporting company, as defined by 17 CFR § 229.10(f)(1), and therefore is not required to provide the information otherwise required by this Item.

ITEM 7: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion and analysis presents management's perspective of our business, financial condition, and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition, and outlook for the future, and should be read in conjunction with Items 1 and 2: Business and Properties and Item 8: Financial Statements and Supplementary Data of this Form 10-K. Amounts expressed in British pounds sterling are indicated as "GBP" and in Australian dollars as "AUD".

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Forward looking statements are not guarantees of future performance, and our actual results may differ significantly from the results expressed or implied in the forward looking statements. See "Forward Looking Statements" at the end of this section. Factors that might cause such differences include, but are not limited to, those discussed in Item 1A: Risk Factors of this Form 10-K. We assume no obligation to revise or update any forward looking statements for any reason, except as required by law.

OVERVIEW

The Company's principal focus over the past four years has been to unlock the potential value of its asset at the Poplar field in Montana by establishing the potential volumes of additional hydrocarbons that may be recovered from the field through CO_2-EOR, which we believe should result in a material increase in the value of this asset for the Company's shareholders. The Company has also maintained its exposure to the potential of certain large prospects in its international portfolio and monetized its mature and non-core international assets to finance its activities including the CO_2-EOR pilot at Poplar. During fiscal year 2015, the Company has obtained encouraging technical results for its CO_2-EOR project at Poplar, however, the Company's ability to convert these technical results in value creation for the Company's shareholders by obtaining a partner to develop Poplar or to monetize the Company's interests in Poplar is likely going to be negatively impacted by the currently depressed commodity price environment.

Foremost, after several years of extensive engineering analysis and material investment in the Poplar CO_2-EOR pilot program, we estimate that utilization of the CO_2-EOR technique on a full field basis at Poplar could provide access to substantial additional hydrocarbon resources. We believe that although the current commodity price environment presents a challenge to economically develop Poplar using CO_2-EOR, the additional recoverable hydrocarbons, combined with the expected long life of this asset, is a potentially attractive long-term investment. Based on our detailed economic analysis of the project, we expect that the development of Poplar through CO_2-EOR will require significant capital, the amount of which we estimate in the hundreds of millions of dollars. Consequently, in light of the Company's currently constrained capital resources and the significant capital requirements to develop Poplar using CO_2-EOR, on June 5, 2015, the Company formed the Special Committee to consider various strategic alternatives potentially available to the Company, which may include, but are not limited to, sales of some or all of the assets of the Company, joint ventures, a recapitalization, and a sale or merger of the Company. The Special Committee has been and continues to be actively engaged in the strategic alternative review process, and is currently in discussions with various potential parties regarding a potential transaction or series of transactions. However, as of October 9, 2015, no decision on any particular strategic alternative or transaction has been reached, and there is no assurance that any future agreement will be reached, or that any future sale or other strategic alternative transaction or transactions will occur.

The commodity price environment coupled with the cost of the CO_2-EOR pilot has resulted in a significant reduction in the Company's cash and cash equivalent balance and accelerated the need for the Company to enter into a transaction or series of transactions to develop or monetize Poplar and certain of the Company's other assets and raised substantial doubt about the ability of the Company to continue as a going concern.

As regards to the Company's international portfolio, following the rationalization of our international assets during fiscal year 2014, we were able to progress these assets despite a challenging commodity price and political environment while avoiding expending significant capital.

In the UK, with our partner Horse Hill Development, we drilled and completed a well at Horse Hill. The overall assessment of the Horse Hill well remains subject to the results of a flow test currently expected to be conducted by the end of calendar year 2015. In the drilling of the well, we collected valuable data to further establish the potential of the Kimmeridge and several other formations in the Weald Basin. In the UK, our interest in the licenses co-owned with Celtique remain encumbered by an ongoing litigation process.

In Australia, we maintained our exposure to the potential in the energy sector through our remaining investment in the shares of Central, acquired as partial consideration for the sale of the Palm Valley and Dingo fields in fiscal year 2014, and we currently own approximately 27.4 million shares of Central. During fiscal year 2015, however, the share price of Central significantly declined from AUD $.32 to AUD $.14 per share, coinciding with the significant drop in commodity prices and the prices of shares of other companies operating in the energy sector over the same period.

During fiscal 2015, Central acquired 50% of the Mereenie field in Australia and based on the potential development of a pipeline to connect the Northern Territory and New South Wales gas pipeline networks, Central may benefit from the higher priced gas markets of Eastern Australia and unlock significant reserves. As a result of the Company's currently constrained liquidity position, we currently consider the shares of Central as a source of liquidity to finance the operations of the Company. The reduction in commodity prices has negatively affected our efforts to farmout our interests in NT/P82, a block offshore in the Bonaparte Basin, Australia. In July 2015, we engaged a financial adviser to assist in obtaining a farmout during fiscal year 2016.

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Following the sale of the Company's assets onshore Australia during fiscal year 2014, the subsequent closing of our office in Brisbane, Australia, and various cost reductions other efforts at the corporate level, Magellan now has limited indebtedness, cost commitments, and contingent liabilities. The cash general and administrative expenses for fiscal year ended June 30, 2015, amounted to approximately $7.1 million, and we estimate that excluding certain transaction related expenses, the Company's cash general and administrative expense level could be approximately $5.5 million for the upcoming twelve month period. We believe that the public status of the Company carries intrinsic value for shareholders and in the context of the strategic alternative review process.

SIGNIFICANT DEVELOPMENTS IN FISCAL YEAR 2015

During fiscal year 2015, the Company achieved a number of key milestones in the strategy of creating value from our existing assets.

Progress on Key Projects

Poplar CO_2-EOR pilot project. During fiscal year 2015, the Company continued to monitor, collect data, and develop the five-well CO_2-EOR pilot program at Poplar that began in fiscal year 2014. In May 2015, the Company determined that CO_2-EOR is a technically viable technique for recovery of hydrocarbons from the Charles formation at Poplar. Based on the results of the CO_2-EOR pilot project to date and our analysis of the data from the pilot as integrated into our reservoir simulation model, we believe that utilization of the CO_2-EOR technique on a full field basis at Poplar could provide access to substantial additional hydrocarbon resources that could result in attractive financial returns from production over a 40 year period.

The CO_2-EOR pilot project consisted of drilling four producer wells and one CO_2 injection well to a total depth of approximately 5,800 feet, completing the wells in the B-2 zone of the Charles formation, performing water shut-off treatments in all five wells, and installing the necessary surface facilities and CO_2 injection equipment. In August 2014, the Company commenced the continuous injection of volumes of CO_2 into the B-2 zone of the Charles formation through the injector well, EPU 202-IW. In early October 2014, the Company opened for production the four producer wells. Initial production from these wells was mainly water with negligible traces of oil. In early January 2015, two of the four pilot producer wells began to exhibit oil production with improving oil cuts. Since then, oil production has increased in three of the four producer wells in response to CO_2 injection, with a peak oil production rate of approximately 50 bopd. In June 2015, the Company stopped injecting CO_2 and started injecting water, pursuant to a water alternating gas process (the "WAG" process). The purpose of a WAG process is to optimize the sweep efficiency of the CO_2 by reducing the total volume of CO_2 required to mobilize the oil that remains in the reservoir. Throughout the year, all data gathered by the Company from the pilot has been continuously integrated into the Company's reservoir simulation model and reviewed by third party consultants. Based on the reservoir simulation model, the Company then created a potential development plan for the Charles formation of Poplar using CO_2-EOR, which forms the basis of the Company's estimate of substantial additional hydrocarbons that may be produced from CO_2-EOR. The development plan details the various phases of drilling activity, including the number of production and injection wells necessary, the amount of CO_2 required to "sweep" the Charles formation and the estimated resulting oil production over approximately a forty year period. The results of the reservoir simulation model also suggest that the utilization rate of CO_2, which represents the amount of CO_2 required to recover volumes of oil from Poplar on a unit basis, and which represents the sweep efficiency of the CO_2-EOR technique, is in line with several other projects to which CO_2-EOR technique has been applied.

In addition, during fiscal 2015, the Company evaluated the availability, feasibility and costs of certain key aspects of the potential development plan of Poplar using CO_2-EOR, including the sources of CO_2 which could be available to the project within a reasonable distance, the pipeline to transport the CO_2 from its potential sources to Poplar, and the surface facilities and their ancillary requirements, and integrated this information in the development plan of Poplar. As regards to sources of CO_2, we identified two potential suppliers and initiated discussions with each, and believe that a long term, reliable source of CO_2 at a reasonable price could be available to the Company. The Company then integrated all the information available to analyze the potential development plan for Poplar using CO_2-EOR and concluded that the development of Poplar using CO_2-EOR will require significant capital to invest, the amount of which we estimate at several hundreds of millions of dollars and that the economic viability will depend on a recovery of oil prices. Considering that the development of Poplar is expected to span over several decades and the incremental volume of oil potentially recoverable from Poplar using CO_2-EOR, we believe that this asset should be attractive to potential investors that would have a long term view of the oil industry and commodity prices. Also considering the significant capital requirement of the potential development plan of Poplar and in light of the current capitalization of the Company, we believe that a significant partner is needed to support the development of this project both financially and operationally, which led the Company to initiate the strategic alternative review process in June, 2015.

Utah CO2. During fiscal 2015, Magellan formed Utah CO2 a majority owned subsidiary focused on the acquisition of sources of CO_2 in Utah and identification of potential candidate fields for CO_2 EOR projects. On December 1, 2014, Magellan,

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through Utah CO2, entered into an option agreement (the "Utah CO2 Option Agreement") to either i) acquire a large CO_2 reservoir called Farnham Dome located in Carbon County, Utah or ii) enter into an agreement to purchase uncontracted CO_2 volumes at a fixed price (the "CO_2 Purchase Agreement"). In May 2015, Utah CO2 elected to exercise the right to enter into the CO2 Purchase Agreement, the key terms of which are to be consistent with the terms detailed in the Option Agreement, which included a fifty year term, an attractive CO_2 price per mcf, the exclusive access to CO_2 volumes recoverable from Farnham Dome for CO_2-EOR projects in Utah, and no CO_2 purchase obligations for the first three years. Based on our preliminary analysis, several oil fields located within approximately a 100 mile radius of Farnham Dome could be attractive candidates to become CO_2-EOR projects. Considering that long term, cost competitive access to CO_2 is a critical component to enable the development of oil fields using the CO_2-EOR technique, the CO_2 Purchase Agreement, if finalized and executed, is expected to provide Utah CO2 with exposure to and an investment opportunity with several potential CO_2-EOR projects in Utah. We believe that the investment in this new venture is complementary to the Poplar asset, and since no CO_2 purchase obligations are expected to be required for at least three years under the terms of the CO_2 Purchase Agreement, Utah CO2 is expected to provide a cost effective way to grow the Company's activities in CO_2-EOR.

UK - Horse Hill. Magellan currently maintains non-operating interests in PEDLs 137 and 246, representing approximately 12 thousand net acres, that may be prospective for conventional oil and gas targets. PEDLs 137 and 246 cover the Horse Hill structure. Magellan is encouraged by the technical analysis performed on the Horse Hill prospect by its partner, HHDL, a 65% interest owner of the Horse Hill-1 well ("HH-1") and UKOG, which through its direct and indirect investments controls approximately 20.4% of HH-1. HH-1, spud in August 2014, confirmed that the Upper Jurassic section is thermally mature (i.e., in the oil window) and contains two thick limestone intervals that may act as conventional reservoirs for a significant oil play in the Weald Basin. This confirmation suggests that the Upper Jurassic throughout the greater Weald Basin is also thermally mature, and therefore serves as an important data point in evaluating the potential of the Company's Central Weald licenses. HH-1 is expected to be put on a production test from the Portland Sandstone section in the first half of fiscal year 2016, pending regulatory approvals. Pursuant to a farmout agreement executed in December 2013, Magellan owns a 35% working interest in the HH-1 well and is being carried for its share of well costs through testing and completion.

UK - Central Weald Basin Licenses. During fiscal year 2015, Celtique, the equal co-owner with the Company, and operator of the three licenses in the central Weald basin, PEDLs 231, 234, and 243, initiated a legal proceeding against the Company for the payment of an advancement of estimated expenses in the amount of $2 million in connection with the first exploratory well, the Broadford Bridge-1 well that was planned to be spud on PEDL 234 during the year. Celtique applied for a summary judgment in the UK court of law and in June 2015, the judge rejected the application primarily due to Magellan's real prospect of defending the claim from Celtique. Amongst other things, Magellan disputes that the amount of the cash calls was in fact going to be spent at the time of the cash call. The judge also awarded GBP 60 thousand to Magellan to be paid by Celtique for the reimbursement of certain costs the Company incurred in relation to the litigation. At the time of this report, the litigation between Celtique and Magellan continues. For additional information, see Note 14 - Commitments and Contingencies - Celtique Litigation, in the Notes to the Consolidated Financial Statements included in this report. PEDLs 231, 234, and 243 represent approximately 124 thousand net acres that may be prospective for oil and gas development from the Kimmeridge Clay, Liassic, and other formations. These licenses are subject to drill-or-drop obligations and will expire in June, 2016 unless such obligations are met.

Other UK Licenses. During fiscal year 2015, Magellan continued to reduce its interest in its licenses on the periphery of the Weald Basin. In April 2015, the Company sold for nominal consideration its 40% interest in PEDL 126, the exploration license that contains the Markwells Wood-1 wellbore ("MW-1"). By selling the license and the wellbore, the Company eliminated approximately $346 thousand of asset retirement obligations related to MW-1. Following the sale of its interest in PEDL 126, the Company continues to hold a 23% interest in PEDL 1916, located offshore southern UK, near the Isle of Wight.

Australia NT/P82. During the fiscal year 2015, the Company sought a suitable farmout partner experienced in offshore drilling to drill and carry Magellan for the work commitment obligation in exchange for a portion of its working interest and operatorship of the NT/P82 exploration block in the Bonaparte Basin. However, the Company was unable to complete a farmout agreement during the year. In June 2015, the National Offshore Petroleum Titles Administrator ("NOPTA") approved the variation of the minimum work requirements to be conducted by May 12, 2016 from the drilling of a well in the block to a 600 km^2 3-D seismic program. NOPTA also advised that a suspension and extension of the work requirement for the permit year ending May 12, 2015, and a potential delay of the 3-D seismic program to be conducted during the permit year ending May 12, 2016, may be considered. This variation is expected to allow the Company greater flexibility in obtaining partner(s) and executing a farmout of this exploration block.

OUTLOOK FOR FISCAL YEAR 2016

2016 will be a year of transition and transformation for Magellan. Over the past four years, we have focused our efforts on establishing the potential value of Poplar, by demonstrating the technical viability of recovering incremental volumes of oil

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using the CO_2-EOR technique. Although continuing the CO_2-EOR pilot could further refine our technical evaluation of the project, we believe that considering i) we estimate that the development of Poplar on a full field basis using CO_2-EOR technique will require several hundreds of millions of dollars, ii) the current liquidity position of the Company, and iii) the currently depressed commodity price environment, we believe that the Company and Poplar need the technical and financial support of a larger partner. Consequently, on June 5, 2015, the Company formed a special committee of independent members of the Board of Directors of the Company (the "Special Committee") to consider various strategic alternatives potentially available to the Company. The formation of the Special Committee was not in response to any proposal received by the Company or an approach by a third party. The Special Committee is authorized to identify, consider, negotiate, and potentially implement all strategic alternatives reasonably available to the Company, including, but not limited to, sales of some or all of the assets of the Company, joint ventures, a recapitalization, and a sale or merger of the Company. The Special Committee engaged Petrie Partners, LLC as financial advisor to assist in the consideration of such matters. The Special Committee has been and continues to be actively engaged in the strategic alternative review process, and is currently in discussions with various potential parties regarding a potential transaction or series of transactions. However, as of the filing date of this report, no decision on any particular strategic alternative or transaction has been reached, and there is no assurance that any future agreement will be reached, or that any future sale or other strategic alternative transaction or transactions will occur.

Over the past four years, the Company also conducted a gradual rationalization of its international portfolio, the objective of which rationalization was to allow the Company to evaluate the potential value of these assets, monetize them at what we believed was an optimal time to maximize value for shareholders and to finance the Company's other activities. During the next year, we expect to complete this rationalization process by farming out our offshore Australia block, NT/P82, potentially monetize some or all of our interest in Central to finance the Company's activities, and we will endeavor to resolve the litigation with Celtique, which encumbers potential sale or farmout process of some of our UK assets.

CO_2-EOR Pilot Project

During fiscal year 2016, the Company intends to continue collecting data from the CO_2-EOR pilot and refine its technical evaluation, and seek a partner to enable the development of Poplar using CO_2-EOR technique.

Based on the data collected from, and the initial results of the Company's evaluation of the CO_2-EOR pilot, we have been able to conclude that CO_2-EOR is a technically effective technique at Poplar to recover incremental volumes of oil. The Company now intends to focus its efforts on refining its evaluation. In June 2015, the Company stopped injecting CO_2 and started injecting water, pursuant to a WAG process. The purpose of a WAG process is to optimize the sweep efficiency of the CO_2 by reducing the total volume of CO_2 required to mobilize the oil that remains in the reservoir. The Company does not expect to incur further significant costs in relation to the CO_2-EOR pilot in addition to the ongoing operating expenses and CO_2 costs of the CO_2-EOR pilot.

The primary focus of the Company during the fiscal year ending June 30, 2016 will be to obtain a partner to support the future development of Poplar. Based on the results of the Company's reservoir simulation model, we created a plan for the first phase of the full field development of Poplar through CO_2-EOR, which development plan envisions the drilling of approximately 150 wells, including both injection and production wells, the construction of surface facilities, the laying of a pipeline from the long term source of CO_2 to Poplar, and the execution of a contract for a source of CO_2 which remains in discussions. By integrating the results of the reservoir simulation model with the main elements of the first phase development plan into the Company's financial model, we estimated that the cumulative funding required over the initial development phase of the development plan for Poplar would be several hundreds of millions of dollars. Consequently, the Company believes that considering the current commodity price environment and market capitalization of the Company, it may not be able to raise the financing required to develop Poplar using CO_2-EOR on a full field basis and therefore it is in the best interest of the Company's shareholders for the Special Committee to consider strategic alternatives as discussed above and engage a financial advisor to support its efforts to complete a transaction with a partner maximize the value of Poplar.

In addition, the Company is planning to implement certain cost saving initiatives with the objective of reducing the operating losses from Poplar and endeavoring to achieve break-even cash flows from Poplar at current commodity price levels.

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UK - Horse Hill

HHDL, our partner in the Horse Hill well, is planning to conduct a flow test of the conventional formations, particularly the Portland Sandstone and the tight underlying Jurassic-aged formations. Magellan is fully carried by HHDL for the cost of performing the flow test under the terms of the farmout agreement with HHDL. Once the Company receives the results of the flow test, the Company will determine what it believes is the most appropriate path to generate value for its shareholders, which path may include a sale or further farmout agreement of the Company's interest in the Horse Hill well and PEDLs 137 and 246, and which will reflect consideration of the overall political and social environment in the UK with respect to conventional and unconventional oil and gas developments.

UK - Central Weald Licenses

As regards to PEDLs 231, 234, and 243, which are co-owned with Celtique, the Company will endeavor to resolve the pending litigation with Celtique, which resolution could include a potential buyout by one of the two co-owners, or a combined sale process. Considering the pending litigation and that these licenses are subject to drill-or-drop obligations with license terms ending June 30, 2016, there is a risk that the litigation with Celtique will not be resolved in time to avoid the relinquishment of these licenses.

NT/P82, Offshore Australia

Based on the results of the interpretation of the seismic data and following the variation to the terms of the license, the Company will continue to seek to identify a farmout partner experienced in offshore drilling. In July 2015, the Company engaged RFC Ambrian as a financial advisor to support the Company's efforts to conduct a farmout process. As part of the potential farmout, the Company expects to relinquish a portion of its working interest in, and operatorship of, NT/P82, in exchange for a commitment from the partner to meet the work requirements under the terms of the license and potential renewal term. Given the high level of offshore drilling activity in the Bonaparte Basin, the network of installed gas infrastructure in the relative vicinity of our block, and the relatively shallow depths of water in the license, the Company believes it is well positioned to successfully execute a farmout agreement during fiscal year 2016.

Australia, Bonus Rights

The Company is entitled to bonus payments under two agreements; the value of the payments is contingent on certain operational results from assets the Company has sold in the past four fiscal years. First, under the terms of the Sale Agreement entered into on September 14, 2011, between Magellan and the Santos Entities, based upon sales of hydrocarbons from the Mereenie field ranging from 2,500 boepd to 10,000 boepd, bonus payments may range from AUD $5.0 million to cumulative potential payments of AUD $17.5 million (the "Mereenie Bonus"). Second, under the terms of the Share Sale and Purchase Deed dated February 17, 2014, between Magellan and Central, the Company is entitled to receive 25% of the revenues generated at the Palm Valley gas field from gas sales when the volume-weighted gas price realized at Palm Valley exceeds AUD $5.00/Gigajoule and AUD $6.00/Gigajoule for the first 10 years following the closing date of March 31, 2014, and for the following 5 years, respectively, with such prices to be escalated in accordance with the Australian CPI (the "Palm Valley Bonus"). For further information related to the Palm Valley Bonus, please refer to the Note 2 - Sale of Amadeus Basin Assets of the Notes to Consolidated Financial Statements included in this report. The value of the rights to these bonus payments is not reflected on the Company's financial statements and the Company believes there is significant risk to the potential realization of value from these rights.

The Australian government is currently considering awarding a contract to develop a pipeline interconnection between the Amadeus Gas Pipeline located in the Northern Territory, Australia and the New South Wales gas pipeline network, which is commonly referred to as the NT Gas Interconnect ("NEGI"). NEGI could allow additional gas to become available to supply the LNG terminals currently under construction in Queensland, which tend to benefit from higher sale prices than current gas sales contracts in the Northern Territory. If NEGI becomes certain, we believe that i) the probability of a potential increase in sales of hydrocarbons from the Mereenie field could increase, which could enhance the potential value of our bonus rights related to sales of hydrocarbons from the Mereenie field, and ii) the probability of an increase in the price of gas sales from Palm Valley above AUD $5.00 per Gigajoule could increase, which could enhance the potential value of our bonus rights related to sales of gas from Palm Valley.

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SUMMARY RESULTS OF OPERATIONS FOR THE YEAR ENDED JUNE 30, 2015

As a result of the sale of the Amadeus Basin assets in March 2014, results of operations related to these assets have been reclassified as discontinued operations. Accordingly, the revenue and adjusted EBITDAX amounts presented immediately below for fiscal year 2014 exclude the impact of these assets on such amounts.

Revenues. Revenues for the fiscal year ended June 30, 2015, totaled $4.5 million, compared to $7.6 million in the prior year, a decrease of (41)%. The $3.1 million decrease in revenue from the prior year was primarily due to both a decrease in the average sales price realized from production from the field ($2.5 million), and a decrease in production volumes ($0.6 million) resulting from the natural production decline of the Poplar field as a result of a reduction in the level of workover activity. The decrease in realized price resulted from a decrease in WTI, the benchmark price during the period.

Loss from continuing operations. Loss from continuing operations totaled $43.4 million ($7.83/basic share), compared to a loss from continuing operations of $10.0 million ($2.07/basic share) in the prior year. The increase in loss from continuing operations was primarily the result of an impairment loss on proved properties of $17.4 million and a loss recognized on our available-for-sale investment in securities of $15.1 million in the current year.

Adjusted EBITDAX. Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part I, Items 1 and 2: Business and Properties) was negative $7.7 million, compared to negative $5.6 million in the prior year, a change of 39%. The decline in Adjusted EBITDAX resulted from a decrease in revenues of $3.1 million, partially offset by a decrease in lease operating expense of $1.2 million and a reduction in general and administrative expense (excluding stock based compensation and foreign transaction loss) of $0.5 million.

Cash. As of June 30, 2015, Magellan had $1.1 million in cash and cash equivalents, compared to $16.4 million at the end of the prior fiscal year. The decrease of $15.4 million was the result of net cash used in operating activities of $8.6 million, net cash used in investing activities of $9.3 million, net cash provided by financing activities of $3.2 million, and a decrease in cash from the effect of changes in exchange rates of $0.7 million. The $8.6 million of net cash used in operating activities was primarily due to a $0.6 million operating loss at Poplar and general and administrative expenses, net of stock based compensation expense and foreign transaction losses of $7.1 million. The $9.3 million of net cash used in investing activities was primarily the result of $9.1 million of capital expenditures, the majority of which related to the CO_2-EOR pilot at Poplar.

Securities available-for-sale. As of June 30, 2015, Magellan had $4.2 million in securities available for sale, consisting of the Company's investment in shares of Central stock. The Company faces no restrictions other than insider trading restrictions relevant to this stock and can liquidate a portion or all of these shares if needed to fund its other projects or obligations.

CONSOLIDATED LIQUIDITY AND CAPITAL RESOURCES

During the twelve months ended June 30, 2015, the Company used $15.4 million in cash and, as of June 30, 2015, had $1.1 million in cash and cash equivalents on its balance sheet. The decline in cash and cash equivalents is primarily the result of i) managing the CO_2-EOR Pilot program and the cost of injecting CO_2 in and at Poplar, ii) the loss from operations at Poplar primarily due to the decrease in oil prices, iii) and the Company’s general and administrative expenses. As of October 9, 2015, the cash balances of the Company amounted to approximately $620 thousand and the Company is facing significant liquidity constraints in the short term. The Company has sold some of its shares in Central and currently intends to continue to sell shares of Central to finance the Company’s activities and to manage its operational cash flows in the short-term. On June 5, 2015, the Company formed the Special Committee to identify, consider, negotiate, and potentially implement all strategic alternatives reasonably available to the Company, including, but not limited to, sales of some or all of the assets of the Company, joint ventures, a recapitalization, and a sale or merger of the Company. There can be no assurance that any transaction will occur. Considering the current liquidity position of the Company, there is a risk that the Company will not be able to finance its activities until such time that a transaction, if any, can be completed or that the Special Committee efforts do not result in a transaction or series of transactions that allow the Company to continue as a going concern.

Since June 30, 2015, and through October 9, 2015, the Company has sold shares of Central in the open market and generated approximately AUD $1.3 million of proceeds. As of October 9, 2015, the Company owned approximately 27.4 million shares of Central, which at the closing share price on October 9, 2015 of AUD $0.155 and the foreign exchange rate of 0.72, represented approximately $3.1 million of potential liquidity.

The Company has been implementing certain cost saving initiatives, in particular at Poplar, the impact of which is difficult to quantify due to the many variables involved. Depending upon WTI price and the impact of ongoing cost saving initiatives, we expect that the net cash burn rate at Poplar could range from $0 and $100 thousand per month. We continue to develop cost saving initiatives with the objective of achieving break even at operating level in the current oil price environment. Since August 2015, when the first injection cycle of water instead of CO_2 was completed, we have not resumed injection of volumes of CO_2 in the Pilot. The Company projects that it will incur net cash uses per month ranging between $500 thousand and $750 thousand, which is comprised of the following broad components: (i) net cash burn of approximately $0 thousand to $100 thousand at Poplar; (ii) no additional expenses in relation to running the CO_2-EOR Pilot; (iii) general and administrative expenses of $450 thousand to $550 thousand; and (iv) approximately $50 thousand to $100 thousand in other expenses. The Company is currently working on certain additional measures which could result in further reductions to monthly cash expenditures. The above cash burn rate projections are subject to various risks and uncertainties inherent in management estimates, and actual cash burn rates may differ materially from the projections due to, among other things, (i) changes in oil commodity prices; (ii) other changes in results of operations and cash flows as the Pilot continues to generate additional information; (iii) changes in currently available funds as a result of liquidity constraints or potential alternative funding mechanisms such as those discussed above; or (iv) other risks and uncertainties referred to under “Forward Looking Statements” below.

We believe that, based on the current estimated net cash burn rate of the Company, the sale of shares of Central should be sufficient to finance the Company’s activities for the following five months while the Special Committee continues to advance the strategic alternative review process, and that the Company has the following additional potential means to finance its activities during this period, obtaining a potential bridge loan or a loan from One Stone, a farmout of NT/P82, a farmout of the rights to explore certain deep formations at Poplar, a farmout or sale of the Company’s interests in Horse Hill, and a monetization of the Mereenie and Palm Valley bonus rights discussed above.

Uses of Funds

Capital Expenditure Plans. At Poplar, the Company does not face significant mandatory capital expenditure requirements to maintain its acreage position. Substantially all of the leases are held by production and contain producing wells with reserves adequate to sustain multi-year production. Approximately 80% of the acreage has been unitized as a federal exploratory unit, which is held by economic production from any one well in the unit. As of June 30, 2015, Poplar contained 37 productive wells.

In the Shallow Intervals, which are 100% owned and operated by the Company, discretionary capital expenditure plans for the foreseeable future will be determined primarily by the requirements of the Pilot, which is expected to continue to produce during fiscal year 2016. Ongoing expenditures related to the Pilot have been curtailed significantly. Since August 2015, the WAG process, which consists of alternating periods of injection of CO_2 and water in the injection well of the Pilot, has been halted, which will result in significantly reduced costs related to the operation of the Pilot.

In addition, in the Shallow Intervals the Company has elected to remove from its drilling plan nine previously proved undeveloped ("PUD") locations, which were reflected in the Company’s estimated reserves as of June 30, 2014, and which were located around the current location of the CO_2-EOR pilot and were planned to be developed using the CO_2-EOR technique. Although the Company believes that CO_2-EOR is an effective technique at Poplar, as indicated by the Pilot, the significant uncertainty related to the Company’s ability to receive the financing necessary to fund the drilling cost of these locations led to the decision to remove these prior PUD locations from the Company’s reserves and future capital expenditure plans.

In the Deep Intervals, which are operated by the Company and in which the Company has a working interest of 50% in the majority of the leases, the Company does not intend to incur material capital expenditures in fiscal year 2016.

In the UK, the Company's interests are governed by various PEDLs and one Seaward Production License. PEDLs 231, 234, and 243, which the Company co-owns equally with Celtique, are subject to "drill-or-drop" obligations with a deadline of June, 2016. As previously reported, the Company received a cash call from Celtique for the advancement of estimated expenses in the amount of approximately $2 million in connection with the Broadford Bridge-1 well, and the Company is evaluating its alternatives under the applicable joint operating agreement. Also as previously reported, Celtique initiated a legal proceeding against the Company with respect to that cash call and related issues. See Note 14 - Commitments and Contingencies - Celtique Litigation of the Notes to Consolidated Financial Statements included in this report for further information. The Company cannot predict the ultimate outcome of this matter, which may have a material effect on the ultimate amount and/or timing of the Company’s capital expenditures with respect to PEDLs 231, 234, and 243.

In the UK in PEDLs 137 and 246, where the Horse Hill well was drilled, HHDL, the Company’s 65% partner in these licenses, is planning to conduct a flow test, which is expected to be conducted by the end of calendar year 2015, and the cost of which flow test is due to be fully paid by HHDL in accordance with the terms of the farmout agreement between HHDL and MPUK.

In the Bonaparte Basin, offshore Australia, the Company holds a 100% interest in NT/P82. Under the terms of the permit, as amended in June 2015, the Company is required to obtain 600km^2 of 3-D seismic data on the license by May, 2016.

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Following the completion of prior seismic surveys in the license area and the associated processing and interpretation of the data from these surveys, the Company is actively engaged in a process to obtain a farmout partner, which partner would be expected to obtain the remaining 3-D seismic data on our behalf, and the Company has engaged a financial advisor to assist in the farmout process. The Company does not expect to incur further significant capital expenditures on its own through the end of the term of the license.

Series A Preferred Dividend. The Company may elect at its discretion to pay the quarterly dividends on the Series A Preferred Stock either in cash or in kind. During fiscal year ended June 30, 2015, the Company paid the dividend in cash for the quarter ended September 30, 2014, and in kind for the other three quarters of the fiscal year. The decision to pay the dividend in cash for the quarter ended September 30, 2014, was primarily driven by the per share market price of the Company's common stock being materially higher than the Series A Preferred Stock conversion price of approximately $1.22 per share prior to the effect of the reverse stock split (the "Conversion Price"). Similarly, the decision to pay the dividend in kind for the other three quarters of fiscal year ended June 30, 2015, was primarily driven by the per share market price of the Company's common stock being materially lower than the Conversion Price, and the Company's efforts to conserve cash. In the future, the Company intends to pay the dividend in kind, unless the Company's common stock share price materially exceeds the Series A Preferred Stock Conversion Price, which amounts to approximately $9.78 per share following the impact of the 1-for-8 reverse-split basis (the "Adjusted Conversion Price"), and the Company has available the necessary cash resources. In such cases, the Company may decide to issue shares of common stock to finance the cash dividend in order to realize a positive arbitrage between the common stock share price and the Conversion Price.

Contractual Obligations. Please refer to the contractual obligations table below in the Part II, Item 7 of our 2015 Form 10-K for information on all material contractual obligations as of June 30, 2015.

Share Repurchase Program. On September 24, 2012, the Company announced that its Board of Directors had approved a stock repurchase program whereby the Company was authorized to repurchase up to a total value of $2.0 million in shares of its common stock. During November 2012, the Company repurchased 18,692 shares pursuant to this program. As of June 30, 2014, $1.9 million in value of shares of common stock remained authorized for repurchase under this program. This authorization superseded the prior plan announced on December 8, 2000, and expired on August 21, 2014, with no further repurchases of stock.

Sources of Funds

Cash and Cash Equivalents. On a consolidated basis, the Company had approximately $1.1 million of cash and cash equivalents as of June 30, 2015, compared to $16.4 million as of June 30, 2014. The Company considers cash equivalents to be short term, highly liquid investments that are both readily convertible to known amounts of cash and so near to their maturity that they present insignificant risk of changes in value because of changes in interest rates. Due to the international components of its operations, the Company is exposed to foreign currency exchange rate risks and certain legal and tax constraints in matching the capital needs of its assets and its cash resources. To the extent that the Company repatriates cash amounts from MPUK to the US, the Company is potentially liable for incremental US Federal and state income tax, which may be reduced by the US Federal and state net operating loss and foreign tax credit carry forwards available to the Company at that time. As of June 30, 2015, the Company had foreign tax credit carry forwards amounting to $9.1 million, which, based on the Company’s estimated tax rate as of June 30, 2015, have the potential to offset approximately $24.6 million of taxable income. Additional information about the Company’s tax attributes is available in Note 8 - Income Taxes of the Notes to Consolidated Financial Statements included in this report.

Central Shares. The Company currently intends to continue to gradually monetize its position in Central’s stock to finance its activities. The Company is not constrained in its ability to sell its shares in Central by contractual arrangements with Central. Since June 30, 2015, through October 9, 2015, the Company has sold approximately 12.1 million shares, and currently owns approximately 27.4 million shares of Central, which based on the Central closing price on October 9, 2015, represent a total value of $3.1 million of potential liquidity. The Company believes that Central is executing its operational projects in line with its stated plans at the time of the issuance of this stock to Magellan and that these projects have upside value potential material to the valuation of Central relative to its current share price. On September 1, 2015, Central completed the acquisition of a 50% interest in the Mereenie oil and gas field from Santos and became the operator. NEGI, if it becomes certain, is expected to favorably impact Central's share price. On July 21, 2015, Central announced that if NEGI becomes certain, Central will be able to materially increase its 2P reserves.

Existing Credit Facilities. A summary of the Company's existing credit facilities is as follows:

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	June 30, 2015	June 30, 2014
	(in thousands)	
Outstanding borrowings:		
Term loan, due June 30, 2020	$5,500	$—
Total	$5,500	$—

The Company, through its wholly owned subsidiary NP, maintains a term loan (the "Term Loan") with West Texas State Bank ("WTSB"). As of June 30, 2015, the outstanding amount of the Term Loan was $5.5 million. There are no additional amounts available to borrow under the Term Loan. The Term Loan will mature on June 30, 2020, and is subject to monthly floating interest payments based on the Prime Rate (currently approximately 3.25%) plus 1.50% and a floor rate of 4.75%. From July 1, 2015 to June 30, 2016, the payment obligations under the Term Loan will consist of interest payments only, and from July 1, 2016 to June 30, 2020, the payment obligations will include the interest payment and the amortization payments of the principal amount of the Term Loan. The Term Loan is secured by substantially all of NP's assets, including a first lien on NP's oil and gas leases from the surface to the top of the Bakken, but excluding any rights to assets within or below the Bakken. Magellan, the parent entity of NP, provided a guarantee of the Term Loan secured by a pledge of its membership interest in NP. Magellan and NP are subject to certain customary restrictive covenants under the terms of the Term Loan. As of June 30, 2015, the Company was in compliance with all such covenants.

Registered Equity Facility. On December 24, 2014, the Company implemented an "at-the-market" (ATM) facility under which the Company can raise up to $10 million through the issuance of new common shares into the market. The ATM facility is registered under the Company's "shelf" registration statement on Form S-3 (the "Shelf"), which was filed with the U.S. Securities and Exchange Commission on November 17, 2014, and which went effective on December 3, 2014. The Shelf registered the issuance of up to $100 million in equity securities of the Company and is currently planned to be effective through December 2017.

Depending on various factors, including market conditions for the Company's equity securities, the Company may use the ATM facility and the Shelf on an as-needed basis for general corporate purposes, which may include the payment of dividends on its Series A Preferred Stock or the funding of the development of the Company's CO_2-EOR business at Poplar or in Utah. The Company has no immediate plans to issue shares pursuant to the ATM facility or the Shelf, which are intended to provide financial flexibility going forward. As of the date hereof, no securities have been issued under either the Shelf or the ATM facility.

Other Sources of Financing. In addition to its existing liquid capital resources, the Company has various alternatives to fund its activities. In addition to the alternatives to address short-term liquidity issues discussed above, these alternatives could potentially include mezzanine financing from a bank and the alternative investment markets, equity issuances via a PIPE or secondary offering, and a partial or complete divestiture or farmout of a portion of the development program of some of the Company's assets. In addition, if NEGI in Australia becomes certain, the potential value of the bonus rights related to Mereenie and Palm Valley discussed above may be enhanced, which rights could potentially be monetized.

Contractual Obligations. The following table summarizes our obligations and commitments as of June 30, 2015, to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods as follows:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Asset retirement obligations	$2,647	$—	$—	$1,476	$1,171
Contingent consideration payable [(1)]	—	—	—	—	—
Term Loan [(2)]	6,272	261	3,136	2,875	—
Operating leases (3)	424	173	251	—	—
Total	$9,343	$434	$3,387	$4,351	$1,171

(1) Assumptions for the timing of these payments are based on our reserve report and planned drilling activity.
(2) Includes commitments for interest payments according to loan amortization schedule totaling $772 thousand.
(3) Amounts are presented net of guaranteed sublease income totaling $207 thousand over the term of one of the lease agreements.

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Cash Flows

The following table presents the Company's cash flow information for the fiscal years ended:

	June 30, 2015	2014
	(In thousands)	
Cash (used in) provided by:		
Operating activities	$(8,586)	$(11,668)
Investing activities	(9,328)	(2,369)
Financing activities	3,204	(680)
Discontinued operations	—	(1,443)
Effect of exchange rate changes on cash and cash equivalents	(661)	113
Net decrease in cash and cash equivalents	$(15,371)	$(16,047)

Cash used in operating activities during the year ended June 30, 2015, was $8.6 million, compared to cash used of $11.7 million in 2014. The decrease in cash used in operating activities primarily resulted from a combination of a decrease in operating expenses of $1.2 million and general and administrative expenses (excluding stock based compensation and foreign transaction loss) of $0.2 million, which was partially offset by a decrease in revenues of $3.1 million, and timing differences related to the payment of accounts payable and accrued liabilities of continuing operations.

Cash used in investing activities during the year ended June 30, 2015, was $9.3 million, compared to cash used of $2.4 million in 2014. During the fiscal year 2014, $18.6 million in cash proceeds were received from Central pursuant to the Sale Deed for the sale of Palm Valley and Dingo, which was offset by $20.9 million of capital expenditures spent on the development of our assets. The increase in cash used in investing activities during the fiscal year ending June 30, 2015, was due to the capital expenditures related primarily to the CO_2-EOR pilot project at Poplar, which amounted to $9.1 million.

Cash provided by financing activities during the year ended June 30, 2015, was $3.2 million, compared to cash used of $0.7 million in 2014. Cash provided by financing activities primarily relate to the Term Loan of $5.5 million issued during the year, partially offset by $859 thousand in dividends paid on our Series A Preferred Stock, $983 thousand paid to purchase stock options from a former executive and $566 thousand for the purchase of treasury stock.

During the year ended June 30, 2015, the effect of changes in foreign currency exchange rates negatively impacted the translation of our GBP and AUD denominated cash and cash equivalent balances into US dollars and resulted in a decrease of $661 thousand in cash and cash equivalents, compared to an increase of $113 thousand in 2014.

COMPARISON OF FINANCIAL RESULTS AND TRENDS BETWEEN FISCAL 2015 AND 2014

The following table presents results of operations information for the fiscal years ended:

	June 30, 2015	2014	Difference	Percent change
Poplar:				
Oil revenue (in thousands)	$4,459	$7,601	$(3,142)	(41)%
Oil sales volume (Mbbls)	79	88	(9)	(10)%
Oil sales volume (bopd)	217	241	(24)	(10)%
Average realized oil price ($/bbl)	$56.44	$86.38	-$29.94	(35)%

Oil Revenue

Revenues for the year ended June 30, 2015, totaled $4.5 million, compared to $7.6 million in the prior year, a decrease of 41%. Of the $3.1 million decrease in revenue from the prior year, $2.5 million was attributable to lower commodity prices and $0.6 million was related to lower production.

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Oil Sales Volume

Sales volume for the year ended June 30, 2015, totaled 79 Mbbls (217 bopd), compared to 88 Mbbls (241 bopd) sold in the prior year, a decrease of 10%. The decrease was primarily the result of the natural production decline of the Poplar field and reduced workovers on the wells.

Average Realized Oil Price

The average realized price for the year ended June 30, 2015, was $56.44/bbl, compared to $86.38/bbl in the prior year, a decrease of 35%. The decrease was primarily the result of a decrease in the benchmark pricing (WTI), partially offset by an improvement in the differential realized at the Poplar field. The Company does not currently engage in any oil and gas hedging activities.

Operating and Other Expenses

The following table presents selected operating expenses for the fiscal years ended:

	June 30, 2015	2014	Difference	Percent change
	(In thousands)			
Selected operating expenses:				
Lease operating	$5,089	$6,257	$(1,168)	(19)%
Depletion, depreciation, amortization, and accretion	$1,149	$1,123	$26	*
Impairment of proved oil and gas properties	$17,353	$—	$17,353	—%
Exploration	$1,563	$3,484	$(1,921)	(55)%
General and administrative	$8,611	$9,085	$(474)	(5)%
Selected operating expenses ($/bbl):				
Lease operating	$64	$71	$(7)	(10)%
Depletion, depreciation, amortization, and accretion	$15	$13	$2	15%
Impairment of proved oil and gas properties	$220	$—	$220	—%
Exploration	$20	$40	$(20)	(50)%
General and administrative	$109	$103	$6	6%

(*) Not meaningful.

Lease Operating Expenses. Lease operating expenses decreased by $1.2 million to $5.1 million, or $64/bbl, during the year ended June 30, 2015. The decrease is related to a decrease in operating expenses commensurate with a reduction in production, lower production taxes of $0.5 million as a result of lower commodity prices and production, as well as a decrease in workover expense of $0.6 million due to reduced activity.

Depletion, Depreciation, Amortization, and Accretion. The following table presents depletion, depreciation, amortization, and accretion for the fiscal years ended:

	June 30, 2015	2014	Difference	Percent change
	(In thousands)			
Depreciation and amortization	$199	$210	$(11)	(5)%
Depletion	779	749	30	4%
ARO accretion (1)	171	164	7	4%
Total	$1,149	$1,123	$26	2%

(1) Accretion expense related to continuing operations.

Depletion, depreciation, amortization, and accretion expenses increased by $26 thousand to $1.1 million, or $15/bbl, during the year ended June 30, 2015. The increase in depletion expense was due to an increase in the depletion rate as a result

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of transferring $9.0 million of development costs from wells in progress to proved properties. The costs transfered related to two of the CO_2-EOR pilot wells that began producing in the fourth quarter of 2015.
Impairment of proved oil and gas properties. The Company recorded an impairment related to its proved oil and gas properties of $17.4 million at June 30, 2015. The impairment was the result of the decline in the fair value of its proved reserves due to a decline in commodity prices during fiscal year 2015, as well as the Company excluding PUD reserves from the classification of proved reserves due to the uncertainty related to the Company's ability to continue as a going concern, and to obtain the necessary capital to fund its drilling program related to the development of the PUDs.
Exploration Expenses. Exploration expenses decreased by $1.9 million to $1.6 million, or $20/bbl, during the year ended June 30, 2015. Current year exploration expenses primarily consisted of $0.7 million related to Utah CO2, $0.4 million pertaining to Nautilus Poplar for evaluation of the CO_2-EOR pilot, and $0.4 million spent in the UK for license renewals and evaluation of the Weald Basin prospects. In the prior year, the Company incurred $0.7 million related to PEDLs in the UK that were allowed to expire at the end of their term. Most of the prior year exploration expense of $3.5 million was incurred in relation to the licenses operated by Celtique in the UK, and primarily represent timewriting by consultants and the purchase of long-lead expense items related to PEDL 234 in the UK.
General and Administrative Expenses. The following table presents general and administrative expenses for the fiscal years ended:

	June 30, 2015 (In thousands)	2014	Difference	Percent change
General and administrative (excluding stock based compensation and foreign transaction loss)	$7,084	$6,912	$172	2 %
Stock based compensation	891	2,009	(1,118)	(56)%
Foreign transaction loss	635	165	470	285 %
Total	$8,611	$9,085	$(476)	(5)%

General and administrative expenses decreased by $0.5 million to $8.6 million, during the year ended June 30, 2015. General and administrative expenses, excluding stock based compensation and foreign transaction losses, amounted to $7.1 million, an increase of $0.2 million. This increase primarily resulted from increased legal expenses of $0.5 million related to the reverse-stock-split, the establishment of the ATM facility, formation of Utah CO2 and the dispute with our partner in the UK, as well as an increase in travel of $0.2 million, which were partially offset by a decrease in salary and severance expense of $0.6 million as a result of a reduction in corporate office staff. Approximately $2.0 million was incurred by MPUK and MPA. The decrease in non-cash stock based compensation expense is primarily related to a decrease in expense recognized on performance based equity awards to officers and employees due to forfeitures. Foreign transaction loss was the result of the strengthening of the US dollar against the currencies of our foreign subsidiaries, the Australian dollar and the British pound. During fiscal year 2015, we settled intercompany loans from our foreign subsidiaries and recognized foreign transaction losses on those loans that had previously been recorded as a component of other comprehensive income.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not use off-balance sheet arrangements, such as securitization of receivables, with any unconsolidated entities or other parties.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses, as well as the disclosure of contingent assets and liabilities at the date of our consolidated financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates, and judgments made by management in Note 1 to our consolidated financial statements included in this report. We have outlined below certain more significant estimates and assumptions used in preparation of our consolidated financial statements.

Oil and Gas Properties

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether proved reserves have been discovered. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to exploration expense as dry hole costs and included within the consolidated statement of operations. Exploration expenses include dry hole costs and geological and geophysical expenses. Exploration expenses are also included within the consolidated statement of cash flows and reported as capital expenditures under investing activities when initially incurred. The costs of development wells are capitalized whether those wells are successful or unsuccessful. The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which classification will ultimately determine the proper accounting treatment of the costs incurred.

Oil and Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and the assessment of impairment. As a result, adjustments to depletion and evaluation of impairment are made concurrently with changes to reserves estimates. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB"). Our independent third party engineering firm adheres to the same guidelines when auditing our reserve reports. The accuracy of our reserve estimates is a function of many factors, including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the reserves estimates. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our consolidated financial statements.

Depreciation, Depletion, and Amortization. The provision for depletion of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method and is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions regarding future development and abandonment costs as well as our level of capital spending. If the estimates of total proved or proved developed reserves decline, the rate at which we record depreciation, depletion and amortization ("DD&A") expense increases, which in turn, increases DD&A expense. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates with a high level of precision, as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. Oil and gas properties are assessed quarterly, or more frequently as economic events dictate, for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its fair value. We compare the carrying value of properties to the expected future cash flows on an undiscounted basis using the expected future prices at the date of the assessment to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the cost of the property is written down to fair value, which is determined using a discount rate of 10% to calculate the net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. (see Note 19 - Supplemental Oil and Gas Information (Unaudited) in the Notes to Consolidated Financial Statements included in this report)

Asset Retirement Obligations. Our asset retirement obligations ("AROs") consist primarily of estimated future costs associated with the plugging and abandonment of oil and gas properties. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions, and judgments regarding such factors as costs to satisfy plugging and abandonment and other obligations, future advances in technology, timing of settlements, the credit-adjusted risk-free rate, and inflation rates. In periods subsequent to the initial measurement of the ARO, we must 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 of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact operating results as accretion expense. The related capitalized cost, net of estimated salvage values, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

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Revenue Recognition
We record revenues from the sale of oil in the month in which the delivery to the purchaser occurred and title transferred. We receive payment approximately one month after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, any differences have been insignificant.

Stock Based Compensation
We recognize compensation expense for all share-based payment awards made to employees and directors. Stock based compensation expense is measured at the grant date based on the fair value of the award. Judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. The Company estimates the fair value of performance based options ("PBOs") and time based options ("TBOs") using the Black-Scholes-Merton pricing model. The fair value for market based options ("MBOs") is estimated using Monte Carlo simulation techniques. The simplified method is used to estimate the expected term of stock options due to a lack of related historical data regarding exercise, cancellation, and forfeiture. The valuation methods used incorporate assumptions regarding expected volatility of our common stock, risk-free interest rates, expected term of the awards, and other assumptions regarding a number of complex and subjective variables, which are subject to change. Any such changes could result in different valuations and thus impact the amount of stock based compensation expense recognized. Costs related to TBOs are recognized as an expense on a straight-line basis over the vesting period. MBOs are expensed on a straight-line basis over the derived service period, even if the market condition is not achieved. PBOs are amortized on a straight-line basis between the date upon which the achievement of the relevant performance condition is deemed probable and the date the performance condition is expected to be achieved. Management re-assesses whether achievement of performance conditions is probable at the end of each reporting period. As of June 30, 2015, 332,028 stock options with market based vesting provisions or PBOs were unvested. If changes in the estimated outcome of the performance conditions affect the quantity of the awards expected to vest, the cumulative effect of the change is recognized in the period of change.

Income Taxes and Uncertain Tax Positions
We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of our deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions.
Accounting guidance for recognizing and measuring uncertain tax positions prescribes a more likely than not recognition threshold that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Previously recognized uncertain tax positions that no longer meet the more-likely-than-not threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met. There are no uncertain tax positions that would meet the more-likely-than-not recognition threshold for the fiscal year ended June 30, 2015.

Foreign Currencies and Foreign Currency Adjustment of Intercompany Loans
When intercompany foreign currency transactions between entities included in the consolidated financial statements are of a long term investment nature (i.e., those for which settlement is not planned or anticipated in the foreseeable future) foreign currency translation adjustments resulting from those transactions are included in stockholders' equity as accumulated other comprehensive income (loss). When intercompany transactions are deemed to be of a short term nature, translation adjustments are required to be included in the consolidated statement of operations.

A component of accumulated other comprehensive income will be released into income when the Company executes a partial or complete sale of an investment in a foreign subsidiary or a group of assets of a foreign subsidiary considered a business and/or when the Company no longer holds a controlling financial interest in a foreign subsidiary or group of assets of a foreign subsidiary considered a business. In the event certain intercompany transactions and/or investments are no longer considered long term in nature, any subsequent foreign currency translation adjustments associated with such items could be required to be reflected in the Company's future statements of operations. Accordingly, if foreign currency translation adjustments are required to be reported in our future statements of operations, exchange rate volatility could have a significant effect on future period results of operations.

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During the year ended June 30, 2015, the Company made a determination that it was no longer permanently invested in its foreign subsidiaries because (i) the Company has begun an effort to repay its intercompany balances through the repatriation of cash from these subsidiaries and (ii) the Company is increasingly focusing on its US operations. As such, the Company recorded on its statement of operations an expense reclassification from accumulated other comprehensive loss arising from foreign currency exchange losses on its intercompany account balances.

Accounting for Business Combinations

The Company may pursue acquisitions as opportunities arise in order to grow our business. We have accounted for all of our business combinations to date in accordance with guidelines established by the Financial Accounting Standards Board, using the acquisition method of accounting, which involves the use of significant judgment.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market based weighted average cost of capital rate, adjusted for risk, determined to be appropriate at the time of the acquisition.

The calculation of the contingent consideration payable is a significant management estimate and is calculated using production projections and the estimated timing of production payouts. The Company also utilizes a discount which is consistent with the Company's credit adjusted incremental borrowing rate.

Authoritative Accounting Matters

See "Recently Issued Accounting Standards" under Note 1 for additional information on the recent adoption of new authoritative accounting guidance in Part II, Item 8: Financial Statements and Supplementary Data of this Form 10-K.

MANAGEMENT ANALYSIS OF CERTAIN MARKET RISK ISSUES

The Company is exposed to market risk in the form of foreign currency exchange rate risk, commodity price risk related to world prices for crude oil, and equity price risk related to investments in marketable securities. The exchange rates between the Australian dollar and the US dollar and the exchange rates between the US dollar and the British pound have changed in recent periods, and may fluctuate substantially in the future. Any appreciation of the US dollar against the Australian dollar is likely to result in decreased net income. Because of our UK development program, a portion of our expenses, including exploration costs and capital and operating expenditures, will continue to be denominated in British pounds. Accordingly, any material appreciation of the British pound against the Australian and US dollars could have a negative impact on our business, operating results, and financial condition.

For the twelve months ended June 30, 2015, oil sales represented 100% of total oil and gas revenues. Based on fiscal year 2015 sales volume and revenues, a 10% change in oil price would increase or decrease oil revenues by $0.4 million.

At June 30, 2015, the fair value of our investments in securities available-for-sale was $4.2 million, with all of that amount attributable to the 39.5 million shares of Central received as part of the consideration for the sale of the Amadeus Basin assets. Central's stock is traded on the Australian Securities Exchange (the "ASX"), and we determined the fair value of our investment in Central using Central's closing stock price on the ASX on June 30, 2015, of AUD $0.140 per share, which translated to $0.107 per share in US dollars on that date. Since June 30, 2015, the Company has sold shares of Central in the open market and generated approximately AUD $1.3 million of proceeds. As of the date of this report, the Company continues to own approximately 27.4 million shares of Central, which at the current share price of approximately AUD $0.155 assuming a foreign exchange rate of 0.72, represent approximately$3.1 million of potential liquidity. Due to the number of Central shares that we own and Central's general daily trading volumes, we may not be able to obtain the currently quoted market price in the event we sell our Central shares. In addition, a 10% across-the-board change in the underlying equity market price per share for our investment would result in a $420 thousand change in the fair value of our investments.

At June 30, 2015, the carrying value of cash and cash equivalents was approximately $1.1 million, which approximates the fair value.

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FORWARD LOOKING STATEMENTS

This report contains forward looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward looking statements. The words "anticipate," "assume," "believe," "budget," "could," "estimate," "expect," "forecast," "initial," "intend," "may," "plan," "potential," "project," "should", "will," "would," and similar expressions are intended to identify forward looking statements. These forward looking statements about the Company and its subsidiaries appear in a number of places in this report and may relate to statements about our businesses and prospects, planned or estimated capital expenditures, including estimates of capital expenditures for the potential full field CO_2-EOR development of Poplar, availability of liquidity and capital resources, increases or decreases in oil and gas production, the acquisition or disposition of oil and gas properties and related assets, the ability to enter into acceptable farmout arrangements, revenues, expenses, operating cash flows,projected cash burn rates, progress in developing the Company's projects, future values of those projects or other interests or rights that the Company holds, the process of reviewing potential strategic alternatives for the Company, borrowings, and other matters that involve a number of risks and uncertainties that may cause actual results to differ materially from results expressed or implied in the forward looking statements. These risks and uncertainties include the following: the uncertainties associated with our planned CO_2-EOR program at Poplar, including uncertainties about the technical and economic viability of CO_2-EOR techniques at Poplar, drilling results from the pilot project, the results of CO_2 injection, including the ability to sustain CO_2 pressures at sufficient effective levels to sweep the oil across the formation to production wells, and our ability to acquire a long term CO_2 supply for the program; possible adverse changes to the CO_2-EOR industry; possible geologic or other obstacles to the further development of our Poplar project; possible geologic or other obstacles to obtaining the anticipated production from our CO_2-EOR projects and the timing of development milestones; uncertainties inherent in projecting future rates of production from CO_2-EOR activities, and whether enhanced production expected from CO_2-EOR will be comparable to other CO_2-EOR projects or otherwise meet our expectations; the uncertain nature of oil and gas prices in the US, UK, and Australia, including uncertainties about the duration of the currently depressed oil commodity price environment and the related impact on our revenues, project developments, and ability to obtain financing; uncertainties regarding our ability to maintain sufficient liquidity and capital resources to implement our projects or otherwise continue as a going concern; uncertainties regarding the ability to realize the expected benefits from the sale of the Amadeus Basin assets to Central pursuant to the Sale Deed, including through the future value of Central's stock; uncertainties regarding our ability to successfully acquire CO_2 at Farnham Dome in Utah and realize the expected benefits thereof; our ability to attract and retain key personnel; the likelihood of success of a water shut-off program at Poplar; our limited amount of control over activities on our non-operated properties; our reliance on the skill and expertise of third party service providers; the ability of our vendors to meet their contractual obligations; the uncertain nature of the anticipated value and underlying prospects of our UK acreage position; government regulation and oversight of drilling and completion activity in the UK, including possible restrictions on hydraulic fracturing that could affect our ability to develop unconventional resource projects in the UK; the uncertainty of drilling and completion conditions and results; the availability of drilling, completion, and operating equipment and services; the results and interpretation of 2-D and 3-D seismic data related to our NT/P82 interest in offshore Australia and our ability to obtain an attractive farmout arrangement for NT/P82; uncertainties regarding our ability to maintain the NASDAQ listing of our common stock, and the related potential impact on our ability to obtain financing; risks and uncertainties inherent in management estimates of future operating results and cash flows; risks and uncertainties associated with litigation matters, including the current legal proceeding initiated by Celtique; and other matters discussed in the Risk Factors section of this report. For a more complete discussion of the risk factors that may apply to any forward looking statements, you are directed to the discussion presented in Item 1A ("Risk Factors") of this Form 10-K. In addition, as of the filing date of this report, no decision on any particular strategic alternative or transaction has been reached and there is no guarantee that any future sale or other strategic transaction will occur. Any forward looking statements in this report should be considered with these factors in mind. Any forward looking statements in this report speak as of the filing date of this report. The Company assumes no obligation to update any forward looking statements contained in this report, whether as a result of new information, future events or otherwise, except as required by securities laws. Estimates of probable reserves are by their nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company.

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is a smaller reporting company, as defined by 17 CFR § 229.10(f)(1), and therefore is not required to provide the information otherwise required by this Item.

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ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Magellan Petroleum Corporation
Denver, Colorado

We have audited the consolidated balance sheets of Magellan Petroleum Corporation and subsidiaries (the "Company") as of June 30, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the years ended June 30, 2015 and 2014. Magellan Petroleum Corporation's management is responsible for these consolidated financial statements. 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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated 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 Magellan Petroleum Corporation and subsidiaries as of June 30, 2015 and 2014, and the results of their operations and their cash flows for each of the years ended June 30, 2015 and 2014, in conformity with accounting principles generally accepted in the United States of America.

The consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company has suffered recurring losses from operations and negative cash flows from operations which raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ EKS&H LLLP
October 13, 2015
Denver, Colorado

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

	June 30, 2015	2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,051	$16,422
Securities available for sale	4,230	11,935
Accounts receivable — trade	420	886
Accounts receivable — working interest partners	130	—
Inventories	651	739
Prepaid and other assets	2,100	2,105
Total current assets	8,582	32,087
PROPERTY AND EQUIPMENT, NET (SUCCESSFUL EFFORTS METHOD):		
Proved oil and gas properties	20,857	29,335
Less accumulated depletion, depreciation, amortization and accretion	(4,355)	(3,575)
Unproved oil and gas properties	709	550
Wells in progress	19,660	21,296
Land, buildings, and equipment (net of accumulated depreciation of $682 and $483 as of June 30, 2015, and 2014, respectively)	202	368
Net property and equipment	37,073	47,974
OTHER NON-CURRENT ASSETS:		
Goodwill, net	500	1,174
Deferred income taxes	—	—
Other long term assets	545	200
Total other non-current assets	1,045	1,374
Total assets	$46,700	$81,435
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$2,534	$3,586
Accrued and other liabilities	2,120	2,121
Accrued dividends	—	429
Current portion of asset retirement obligations	—	397
Total current liabilities	4,654	6,533
LONG TERM LIABILITIES:		
Note payable	5,500	—
Asset retirement obligations, net of current portion	2,647	2,476
Contingent consideration payable	—	1,852
Other long term liabilities	98	118
Total long term liabilities	8,245	4,446

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COMMITMENTS AND CONTINGENCIES (Note 14)		
PREFERRED STOCK (Note 10):		
Series A convertible preferred stock (par value $0.01 per share): Authorized 28,000,000 shares; issued and outstanding 21,162,697 and 20,089,436 shares as of June 30, 2015, and 2014, respectively; liquidation preference of $28,435 and $28,220, respectively	25,850	24,539
Total preferred stock	25,850	24,539
EQUITY:		
Common stock (par value $0.01 per share): Authorized 300,000,000 shares, issued 6,917,027 and 6,875,605 as of June 30, 2015, and 2014, respectively	69	69
Treasury stock (at cost): 1,209,389 and 1,178,139 shares as of June 30, 2015, and 2014, respectively	(9,806)	(9,344)
Capital in excess of par value	93,386	93,467
Accumulated deficit	(81,006)	(36,266)
Accumulated other comprehensive income (loss)	5,302	(2,009)
Total equity attributable to Magellan Petroleum Corporation	7,945	45,917
Non-controlling interest in subsidiary	6	—
Total equity	7,951	45,917
Total liabilities, preferred stock and equity	$46,700	$81,435

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

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share and per share amounts)

	For the years ended June 30,	
	2015	2014
REVENUE FROM OIL PRODUCTION	$4,459	$7,601
OPERATING EXPENSES:		
Lease operating	5,089	6,257
Depletion, depreciation, amortization, and accretion	1,149	1,123
Exploration	1,563	3,484
General and administrative	8,611	9,085
Impairment of proved oil and gas properties	17,353	—
Impairment of goodwill	674	—
Loss on sale of assets	316	—
Total operating expenses	34,755	19,949
Loss from operations	(30,296)	(12,348)
OTHER (EXPENSE) INCOME:		
Net interest expense	(83)	(233)
Amortization of deferred financing costs	(100)	(10)
Loss on investment in securities	(15,087)	—
Fair value revision of contingent consideration payable	1,888	2,403
Other income	267	146
Total other (expense) income	(13,115)	2,306
Loss from continuing operations, before tax	(43,411)	(10,042)
Income tax expense	—	—
Loss from continuing operations, net of tax	(43,411)	(10,042)
DISCONTINUED OPERATIONS:		
Loss from discontinued operations, net of tax	—	(4,461)
Gain on disposal of discontinued operations, net of tax	—	30,012
Net income from discontinued operations	—	25,551
Net (loss) income	(43,411)	15,509
Net loss attributable to non-controlling interest in subsidiary	411	—
Net (loss) income attributable to Magellan Petroleum Corporation	(43,000)	15,509
Preferred stock dividends	(1,740)	(1,696)
Net (loss) income attributable to common stockholders	$(44,740)	$13,813
(Loss) earnings per common share (Note 12):		
Weighted average number of basic shares outstanding	5,710,288	5,671,603

Weighted average number of diluted shares outstanding	5,710,288	5,671,603

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Basic (loss) earnings per common share:		
Net loss from continuing operations attributable to Magellan Petroleum Corporation, including preferred stock dividends	$(7.83)	$(2.07)
Net income from discontinued operations	$0.00	$4.51
Net (loss) income attributable to common stockholders	$(7.83)	$2.44
Diluted (loss) earnings per common share:		
Net loss from continuing operations attributable to Magellan Petroleum Corporation, including preferred stock dividends	$(7.83)	$(2.07)
Net income from discontinued operations	$0.00	$4.51
Net (loss) income attributable to common stockholders	$(7.83)	$2.44

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

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	For the years ended June 30,	
	2015	2014
Net (loss) income	$(43,411)	$15,509
Other comprehensive income (loss), net of tax:		
Foreign currency translation (loss) gain	(2,141)	1,237
Reclassification of foreign currency translation loss to earnings upon reversal of permanent investment in foreign subsidiaries	659	—
Reclassification of foreign currency translation gain to earnings upon sale of foreign subsidiary	—	(5,767)
Reclassification of impairment loss on securities available-for-sale to earnings due to determination as other than temporary	15,087	—
Unrealized holding losses on securities available-for-sale	(6,294)	(8,005)
Other comprehensive income (loss), net of tax	7,311	(12,535)
Comprehensive (loss) income	$(36,100)	$2,974

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

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except share and per share amounts)

	Common Stock Shares	Amount	Capital in Excess of Par Value	Treasury Stock	Accumulated Deficit	Accumulated Other Comprehensive Income	Non-Controlling Interest	Total Stockholders' Equity
Fiscal year ended June 30, 2013	6,757,145	$67	$91,259	$(9,333)	$ (50,079)	$ 10,526	—	$ 42,440
Net income	—	—	—	—	15,509	—	—	15,509
Other comprehensive loss, net of tax	—	—	—	—	—	(12,535)	—	(12,535)
Stock and stock based compensation	89,583	1	2,008	—	—	—	—	2,009
Net shares repurchased for employee tax costs upon vesting of restricted stock	—	—	—	(11)	—	—	—	(11)
Stock options exercised, net of shares withheld to satisfy employee tax obligations	28,877	1	200	—	—	—	—	201
Preferred stock dividend	—	—	—	—	(1,696)	—	—	(1,696)
Fiscal year ended June 30, 2014	6,875,605	69	93,467	(9,344)	(36,266)	(2,009)	—	45,917
Formation of and capital contributions to Utah CO2 LLC	—	—	—	—	—	—	417	417
Net loss	—	—	—	—	(43,000)	—	(411)	(43,411)
Other comprehensive loss, net of tax	—	—	—	—	—	7,311	—	7,311
Stock and stock based compensation	30,791	—	1,606	—	—	—	—	1,606
Executive and employee forfeiture of options upon resignation	—	—	(648)	—	—	—	—	(648)
Executive forfeiture of restricted stock upon resignation	(17,500)	—	(67)	—	—	—	—	(67)
Purchase of stock and options from former executive	—	—	(983)	(462)	—	—	—	(1,445)
Net shares repurchased for employee tax costs upon vesting of restricted stock	(5,981)	—	(104)	—	—	—	—	(104)
Stock options exercised, net of shares withheld to satisfy employee tax	34,112	—	115	—	—	—	—	115

obligations								
Preferred stock dividend	—	—	—	—	(1,740)	—	—	(1,740)
Fiscal year ended June 30, 2015	6,917,027	$69	$93,386	$(9,806)	$ (81,006)	$ 5,302	$ 6	$ 7,951

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

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MAGELLAN PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the years ended June 30, 2015	2014
OPERATING ACTIVITIES:		
Net loss (income)	$(43,411)	$15,509
Adjustments to reconcile net loss (income) to net cash used in operating activities:		
Foreign transaction loss	635	165
Amortization of deferred finance costs	100	10
Depletion, depreciation, amortization, and accretion	1,149	1,123
Fair value revision of contingent consideration payable	(1,888)	(2,403)
Accretion expense of contingent consideration payable	36	315
Inventory book to physical adjustment	123	—
Loss on investment in securities	15,087	—
Loss (gain) on disposal of assets	316	(30,012)
Exploration costs previously capitalized	20	733
Stock compensation expense	891	2,009
Impairment of oil and gas properties	17,353	—
Impairment of goodwill	674	—
Net changes in operating assets and liabilities:		
Accounts receivable	478	52
Inventories	(61)	(184)
Prepayments and other current assets	(21)	(704)
Accounts payable and accrued liabilities	(67)	1,719
Net cash used in operating activities of continuing operations	(8,586)	(11,668)
INVESTING ACTIVITIES:		
Additions to property and equipment	(9,073)	(20,923)
Utah CO_2 option	(276)	—
Proceeds from sale of securities	21	—
Proceeds from Amadeus Basin sale	—	18,554
Net cash used in investing activities	(9,328)	(2,369)
FINANCING ACTIVITIES:		
Proceeds from issuance of common stock	115	201
Purchase of common stock	(566)	(11)
Purchase of stock options	(983)	—
Payment of preferred stock dividend	(859)	(429)
Payment of deferred financing costs	(150)	—
Borrowings (repayments) on line of credit, net	—	—
Short term debt issuances	—	1,000
Short term debt repayments	—	(1,441)
Long term debt issuances	5,500	—
Capital contributions by non-controlling interest	147	—
Net cash provided by (used in) financing activities	3,204	(680)

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CASH FLOWS FROM DISCONTINUED OPERATIONS:		
Adjustments to reconcile net loss to net cash used in operating activities of discontinued operations	—	(31)
Net cash used in investing activities of discontinued operations	—	(1,412)
Net cash used in discontinued operations	—	(1,443)
Effect of exchange rate changes on cash and cash equivalents	(661)	113
Net decrease in cash and cash equivalents	(15,371)	(16,047)
Cash and cash equivalents at beginning of period	16,422	32,469
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$1,051	$16,422
Supplemental disclosure of cash flow information:		
Interest paid	$102	$18
Interest received	$(20)	$(102)
Income taxes paid	$—	$—
Supplemental schedule of non-cash investing and financing activities:		
Securities available-for-sale received upon sale of Amadeus Basin assets (Note 3)	$—	$19,147
Unrealized holding loss and foreign currency translation loss on securities available-for-sale	$(7,684)	$(7,256)
Change in accounts payable and accrued liabilities related to property and equipment	$(1,017)	$1,315
Preferred stock dividends paid in kind	$1,311	$1,037
Accrued preferred stock dividends	$—	$429
Increase in both accrued and other liabilities and prepaid and other assets related to Sopak	$105	$571
Property contributed for capital contribution of non-controlling interest	$102	$—
Property contributed for deferred capital contribution of non-controlling interest	$98	$—
Accrued capital contributions of non-controlling interest	$168	$—

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

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MAGELLAN PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 - Basis of Presentation
Description of Operations
Magellan Petroleum Corporation (the "Company" or "Magellan" or "MPC" or "we") is an independent oil and gas exploration and production company focused on the development of CO_2-enhanced oil recovery ("CO_2-EOR") projects in the Rocky Mountain region. Historically active internationally, Magellan also owns significant exploration acreage in the Weald Basin, onshore UK, and an exploration block, NT/P82, in the Bonaparte Basin, offshore Northern Territory, Australia, which the Company currently plans to farmout.
The Company conducts its operations through three wholly owned subsidiaries corresponding to the geographical areas in which the Company operates: Nautilus Poplar LLC ("NP") in the US, Magellan Petroleum (UK) Limited ("MPUK") in the UK, and Magellan Petroleum Australia Pty Ltd ("MPA") in Australia.
Our strategy is to enhance shareholder value by maximizing the value of our existing assets. Our portfolio of operations includes several early stage oil and gas exploration and development projects, the successful development of which requires significant capital, as well as significant engineering and management resources. We are committed to efficiently investing financial, technical and management capital into these projects to establish their technical and economic viability, which in turn could create significant value for our shareholders.
We were founded in 1957 and incorporated in Delaware in 1967. The Company's common stock has been trading on NASDAQ since 1972 under the ticker symbol "MPET".
Our principal executive offices are located at 1775 Sherman Street, Suite 1950, Denver, Colorado 80203, and our phone number is (720) 484-2400.

Going Concern
The Company has incurred losses from operations for the year ended June 30, 2015, of $30.3 million. In addition, during the fiscal year working capital has decreased from $25.6 million at June 30, 2014, to $3.9 million at June 30, 2015, and the Company's cash balance has decreased to $1.1 million as of June 30, 2015. The Company continues to experience liquidity constraints and has begun selling certain of its non-core assets to fund its operations. However, proceeds from these asset sales may not provide sufficient liquidity to fund operations for the next twelve months. These factors raise substantial doubt about the Company's ability to continue as a going concern. The accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or amounts of liabilities that might result from the outcome of this uncertainty.
The Company is currently looking for potential merger candidates that may offer improved liquidity and the ability to raise additional capital. The Company is focused on maintaining production while efficiently reducing its operating and general and administrative costs.

Special Committee of the Board of Directors
On June 5, 2015, the Board of Directors of the Company approved the formation of a special committee of the Board of Directors ("the "Special Committee") to i) engage in a strategic alternatives review process and ii) amend compensation arrangements of executives and employees for the purpose of retention and alignment of interests with the interests of the common stockholders during such strategic alternatives review process.

Principles of Consolidation and Basis of Presentation
The accompanying consolidated financial statements include the accounts of Magellan and its wholly owned subsidiaries, NP, MPUK, and MPA, and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and the instructions to Form 10-K and Regulation S-X published by the US Securities and Exchange Commission (the "SEC"). All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation. Such reclassifications had no effect on the prior year net income, accumulated deficit, net assets, or total shareholders' equity. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of

these consolidated financial statements. All amounts presented

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are in US dollars, unless otherwise noted. Amounts expressed in Australian currency are indicated as "AUD." Amounts expressed in the currency of the United Kingdom are indicated as "GBP."
During the year ended June 30, 2015, the Company formed a majority owned subsidiary, Utah CO2 LLC, a Delaware limited liability company ("Utah CO2"), through which the Company purchased an option to acquire CO_2 at Farnham Dome in Utah. The Company owns a controlling 51% of the equity in Utah CO2 and consolidates this entity in the accompanying consolidated financial statements. The remaining 49% is owned by two separate third parties. Another third-party owns a 10% economic participation interest in the Company's 51% equity interest in Utah CO2, which participation interest does not bear any governance rights over the Company's investment in Utah CO2. The non-controlling interest reported in the accompanying consolidated financial statements relates to the non-controlling interest in this entity, including the participation interest.
As of June 30, 2015 the Company owned an 11% interest in Central Petroleum Limited (ASX:CTP) ("Central"), a Brisbane-based exploration and production company traded on the Australian Securities Exchange. The Company accounts for this investment as securities available-for-sale in the accompanying consolidated financial statements.

Reverse Stock Split
On July 10, 2015, the Company's stockholders approved and the Company completed a one-for-eight reverse stock split with respect to the Company's common stock. For purposes of presentation, the consolidated financial statements and footnotes have been adjusted for the number of post-split shares as if the split had occurred at the beginning of the earliest period presented.

Use of Estimates
The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses, including stock-based compensation expense, during the reporting period. Actual results could differ from those estimates.

Foreign Currency Translation
The functional currency of our foreign subsidiaries is their local currency. Assets and liabilities of foreign subsidiaries are translated to US dollars at period-end exchange rates, and our consolidated statements of operations and cash flows are translated at average exchange rates during the reporting periods. Resulting translation adjustments are recorded in accumulated other comprehensive loss, a separate component of stockholders' equity. A component of accumulated other comprehensive loss will be released into income when the Company executes a partial or complete sale of an investment in a foreign subsidiary or a group of assets of a foreign subsidiary considered a business and/or when the Company no longer holds a controlling financial interest in a foreign subsidiary or group of assets of a foreign subsidiary considered a business.
Transactions denominated in currencies other than the local currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in foreign currency transaction gains and losses that are reflected in results of operations as unrealized (based on period end translation) or realized (upon settlement of the transactions) and reported under general and administrative expenses in the consolidated statements of operations.
During the year ended June 30, 2015, the Company made a determination that it was no longer permanently invested in its foreign subsidiaries because (i) the Company has begun an effort to repay its intercompany balances through the repatriation of cash from these subsidiaries and (ii) the Company is increasingly focusing on its US operations. As such, the Company recorded on its statement of operations an expense reclassification from accumulated other comprehensive loss arising from foreign currency exchange losses on its intercompany account balances.

Cash and Cash Equivalents and Concentration of Credit Risk
The Company considers all highly liquid short term investments with original maturities of three months or less at the date of acquisition to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due

to the short term nature of these instruments.
The Company's financial instruments exposed to concentrations of credit risk consist primarily of cash and cash equivalents. The Company regularly assesses the level of credit risk we are exposed to and whether there are better ways

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of managing credit risk. The Company invests its cash and cash equivalents with reputable financial institutions. At times, balances deposited may exceed FDIC insured limits. The Company has not incurred any losses related to these deposits.

Securities Available-for-Sale

Securities available-for-sale are comprised of investments in publicly traded securities and are carried at quoted market prices. Unrealized gains and losses are excluded from earnings and recorded as a component of accumulated other comprehensive loss in stockholders' equity, net of deferred income taxes. The Company recognizes gains or losses when securities are sold. On a quarterly basis, the Company performs an assessment to determine whether there have been any events or economic circumstances to indicate that a security with an unrealized loss has suffered other-than-temporary impairment. During the year, the Company determined that the value of its investment in Central had suffered an other-than temporary impairment. As such, the unrealized loss was reclassified from other comprehensive income to the consolidated statement of operations.

Accounts Receivable

Trade accounts receivable consist mainly of receivables from oil and gas purchasers. For receivables from working interest partners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and gas receivables are collected within two months. The collectability of accounts receivable is continuously monitored and analyzed based upon historical experience. The use of judgment is required to establish a provision for allowance for doubtful accounts for specific customer collection issues identified. The allowance for doubtful accounts was $0 as of June 30, 2015, and 2014.

Inventories

Our inventories consist of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies, ordinary maintenance materials, and parts and production equipment for use in future drilling operations or repair operations. All inventories are carried at the lower of cost or net realizable value.

Oil and Gas Exploration and Production Activities

The Company follows the successful efforts method of accounting for its oil and gas exploration and production activities. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized until a determination is made that the well has found proved reserves or is deemed non-commercial. If an exploratory well is deemed to be non-commercial, the well costs are charged to exploration expense as dry hole costs. Exploration expenses include dry hole costs, geological, and geophysical expenses. Non-commercial development well costs are charged to impairment expense if circumstances indicate that a decline in the recoverability of the carrying value may have occurred.

The Company records its proportionate share in joint venture operations in the respective classifications of assets, liabilities, and expenses. The cost of CO_2 injection is capitalized until a production response is seen as a result of the injection and it is determined that the well has found proved reserves. After oil production from the well begins, CO_2 injection costs are expensed as incurred.

Depreciation, depletion, and amortization ("DD&A") of capitalized costs related to proved oil and gas properties is calculated on a property-by-property basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the estimated proceeds from salvaging equipment.

The sale of a partial interest in a proved oil and gas property is accounted for as normal retirement, and no gain or loss is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. A gain or loss is recognized for all other sales of producing properties.

Impairment of Long-Lived Assets

The Company reviews the carrying amount of its oil and gas properties and unproved leaseholds for impairment annually or whenever events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected future cash flows of its oil and gas properties and compares such future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the

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carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of estimated future cash flows, net of estimated operating and development costs, using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. The Company undertook such a review during the year ended June 30, 2015, and as a result of the recent decline in oil prices, the Company concluded that its proved oil and gas properties were impaired and recorded an impairment loss of $17.4 million in the accompanying consolidated statement of operations.

Land, Buildings, and Equipment

Land, buildings, and equipment are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to fifteen years.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. GAAP requires goodwill to be evaluated on an annual basis for impairment, or more frequently if events occur or circumstances change that could potentially result in impairment. As of June 30, 2015, management concluded that as a result of the decline in reserve value, principally due to the decline in commodity prices, and a downward revision in reserve quantities as the result of the exclusion of PUD reserves from the Company's reserve estimates, goodwill related to Nautilus Poplar had been impaired and recorded an impairment expense of $0.7 million . There was no impairment of goodwill at June 30, 2014. The qualitative factors used in our assessment include macroeconomic conditions, industry and market conditions, cost factors, and overall financial performance. The quantitative analysis performed included a review of the June 30, 2015 reserve estimates using forward commodity prices and an estimate of the differential less the liabilities for NP, and comparing the result of the analysis to the recorded carrying value of the net assets. The analysis indicated that the carrying value of the net assets exceeded the calculated value of the reserves net of liabilities, and therefore, an impairment had occurred.

As of June 30, 2015, $0.2 million of recorded goodwill related to MPUK, and $0.3 million related to MPA. Changes in goodwill can be summarized as follows for the years ended:

	June 30,	
	2015	2014
	(In thousands)	
Fiscal year opening balance	$1,174	$2,174
Sale of Amadeus Basin assets (see Note 3)	—	(1,000)
Impairment of Nautilus Poplar goodwill	$(674)	
Fiscal year closing balance	$500	$1,174

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the plugging and abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase in the carrying value of the related long-lived asset are recorded at the time a well is acquired or the liability to plug is legally incurred. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs, net of estimated salvage values, and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties (see Note 6).

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Revenue Recognition
The Company derives revenue primarily from the sale of produced oil. Oil revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and collection of the revenue is probable.

Major Customers
The Company's consolidated oil production revenue is derived from its NP segment and was generated from two customers for the year ended June 30, 2015, and a single customer for the year ended June 30, 2014.

Stock Based Compensation
Stock option grants may contain time based, market based, or performance based vesting provisions. Time based options ("TBOs") are expensed on a straight-line basis over the vesting period. Market based options ("MBOs") are expensed on a straight-line basis over the derived service period, even if the market condition is not achieved. Performance based options ("PBOs") are amortized on a straight-line basis between the date upon which the achievement of the relevant performance condition is deemed probable and the date the performance condition is expected to be achieved. Management re-assesses whether achievement of performance conditions is probable at the end of each reporting period. If changes in the estimated outcome of the performance conditions affect the quantity of the awards expected to vest, the cumulative effect of the change is recognized in the period of change.
The fair value of the stock options is determined on the grant date and is affected by our stock price and other assumptions regarding a number of complex and subjective variables. These variables include our expected stock price volatility over the term of the awards, risk free interest rates, expected dividends, and the expected option exercise term. The Company estimates the fair value of PBOs and time based stock options using the Black-Scholes-Merton pricing model. The simplified method is used to estimate the expected term of stock options due to a lack of related historical data regarding exercise, cancellation, and forfeiture. For MBOs, the fair value is estimated using Monte Carlo simulation techniques.

Accounting for Income Taxes
The Company follows the liability method in accounting for income taxes. Under this method, deferred tax assets and liabilities are determined based on differences between the financial reporting and tax bases 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. The Company records a valuation allowance for deferred tax assets when it is more likely than not that such assets will not be recovered.
GAAP prescribes a comprehensive model for recognizing, measuring, presenting, and disclosing in the financial statements uncertain tax positions that the Company has taken or expects to take in its tax returns. Under GAAP, the Company recognizes tax positions when it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the Company has presumed that its positions will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The next step consists of measurement. A tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. A tax position is measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. An uncertain income tax position will not be recognized if it does not meet the more-likely-than-not threshold. To appropriately account for income tax matters, the Company is required to make significant judgments and estimates regarding the recoverability of deferred tax assets, the likelihood of the outcome of examinations of tax positions that may or may not be currently under review, and potential scenarios involving settlements of such matters. Changes in these estimates could materially impact the consolidated financial statements. There are no uncertain tax positions that would meet the more-likely-than-not recognition threshold for the fiscal years ended June 30, 2015, or 2014, respectively.

The Company has adopted an accounting policy to record all tax related interest under interest expense and tax related penalties under general and administrative expense in the consolidated statement of operations.

Financial Instruments

The carrying value for cash and cash equivalents, accounts receivable, accounts payable, and debt approximates fair value based on the timing of the anticipated cash flows and current market conditions.

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Segment Information
As of June 30, 2015, the Company determined, based on the criteria of Financial Accounting Standards Board (the "FASB") ASC Topic 280, it operates in three segments, NP, MPUK and MPA, as well as a head office, Magellan ("Corporate"), which is treated as a cost center. As of June 30, 2015, these three operating segments met the minimum quantitative threshold to qualify for separate segment reporting.
The Company's chief operating decision maker is J. Thomas Wilson (President and CEO of the Company), who reviews the results and manages operations of the Company in the three reporting segments of NP, MPUK, MPA, and Corporate. The presentation of all segment information herein reflects the manner in which the Company's management monitors performance and allocates resources. For information pertaining to our reporting segments, see Note 13 - Segment Information.

(Loss) Earnings per Common Share
Income and losses per common share are based upon the weighted average number of common and common equivalent shares outstanding during the period. The effects of potentially dilutive securities in the determinations of diluted earnings per share are the dilutive effect of stock options, non-vested restricted stock, and the shares of Series A convertible preferred stock.
The potentially dilutive impact of stock options, and non-vested restricted stock is determined using the treasury stock method. The potentially dilutive impact of the shares of Series A Preferred Stock is determined using the "if-converted" method. In applying the if-converted method, conversion is not assumed for purposes of computing dilutive shares if the effect would be anti-dilutive. The preferred stock is convertible at a rate of one common share to one preferred share. We did not include any stock options or common stock issuable upon the conversion of the Series A Preferred Stock in the calculation of diluted earnings (loss) per share during the fiscal year ended June 30, 2015, and 2014, respectively, as their effect would have been anti-dilutive.

Accumulated Other Comprehensive Loss
Comprehensive (loss) income is presented net of applicable income taxes in the accompanying consolidated statements of stockholders' equity and comprehensive (loss) income. Other comprehensive (loss) income is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of stockholders' equity instead of net (loss) income.

Recently Issued Accounting Standards
In August 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-15, which amends presentation and disclosure requirements outlined in ASU 2015-03 (discussed below) by clarifying guidance for debt issuance costs related to line of credit arrangements, providing that the SEC would not object to presentation of debt issuance costs related to a line of credit arrangement as an asset, and amortizing them ratably over the term of the line of credit arrangement. The Company does not expect adoption of ASU 2015-15 to have a material effect on its consolidated financial statements.
In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU 2014-09 (discussed below) by one year, and would allow entities the option to early adopt the new revenue standard as of the original effective date.
In July 2015, the FASB issued ASU No. 2015-11, which requires that inventory that is measured using first-in, first-out or average cost method be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The standard will be effective for the first interim period within the Company's fiscal year beginning after December 15, 2016 and is required to be adopted prospectively; early adoption is permitted. The Company does not expect the adoption of this accounting standard to have a significant impact on its consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, which requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts. Prior to the issuance of ASU 2015-03, debt issuance costs were required to be presented as deferred charge assets, separate from the related debt liability. ASU 2015-03 does not change the recognition and measurement requirements for debt issuance costs. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, and early adoption is permitted. At June 30, 2015, adoption of this standard would have resulted in a reclassification from other long term assets to note payable of $50 thousand on the Company's accompanying consolidated balance sheet.

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In August 2014, the FASB issued ASU No. 2014-15, which provides guidance on management’s responsibility to evaluate whether there is substantial doubt about a company’s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for fiscal years ending after December 15, 2016, and annual and interim periods thereafter. The Company is evaluating the impact of the adoption of this standard on its consolidated financial statements.

In June 2014, the FASB issued ASU No. 2014-12, which requires a reporting entity to treat a performance target included within a share-based payment award that affects vesting and that could be achieved after the requisite service period as a performance condition. It is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early adoption is permitted. ASU 2014-12 may be adopted either prospectively for share-based payment awards granted or modified on or after the effective date, or retrospectively, using a modified retrospective approach. The modified retrospective approach would apply to share-based payment awards outstanding as of the beginning of the earliest annual period presented in the financial statements on adoption, and to all new or modified awards thereafter. The Company has chosen to early adopt this standard retrospectively to July 1, 2013, which adoption did not impact the Company's consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition standard designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In doing so, companies may need to use more judgment and make more estimates than under current revenue recognition guidance. The ASU allows for the use of either the full or modified retrospective transition method, and the standard, as amended by ASU 2015-14, above, will be effective for us in the first quarter of our fiscal year 2019; unless early adopted in the prior fiscal year as permitted under the amendment. The Company is currently evaluating the timing of adoption, which transition approach to use and the impact of the adoption of this standard on its consolidated financial statements.

In February 2013, the FASB issued ASU No. 2013-02 which requires additional disclosures regarding the reporting of reclassifications out of accumulated other comprehensive income. ASU No. 2013-02 requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. This guidance is effective for reporting periods beginning after December 15, 2012. The Company adopted this guidance effective July 1, 2013. The Company's adoption of this standard did not have a significant impact on its consolidated financial statements.

In March 2013, the FASB issued ASU No. 2013-05, which permits an entity to release cumulative translation adjustments into net income when a reporting entity (parent) ceases to have a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity. Accordingly, the cumulative translation adjustment should be released into net income only if the sale or transfer results in the complete or substantially complete liquidation of a foreign subsidiary or foreign group of assets comprising a business. The Company's adoption of this standard did not have a significant impact on its consolidated financial statements.

There are no new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of June 30, 2015.

Note 2 - Sale of Amadeus Basin Assets

On March 31, 2014 (the "Central Closing Date"), pursuant to the Share Sale and Purchase Deed dated February 17, 2014 (the "Sale Deed"), the Company sold its Amadeus Basin assets, the Palm Valley and Dingo gas fields ("Palm Valley" and "Dingo," respectively), to Central through the sale of the Company's wholly owned subsidiary, Magellan Petroleum (N.T.) Pty. Ltd ("MPNT"), to Central's wholly owned subsidiary Central Petroleum PV Pty. Ltd ("Central PV"). In exchange for the assets, Central paid to Magellan (i) AUD $20.0 million; (ii) customary purchase price adjustments amounting to AUD $800 thousand; and (iii) 39.5 million newly issued shares of Central stock (ASX: CTP), equivalent to an ownership interest in Central of approximately 11%.

The Sale Deed also provides that the Company is entitled to receive 25% of the revenues generated at the Palm Valley gas field from gas sales when the volume-weighted gas price realized at Palm Valley exceeds AUD $5.00/Gigajoule

("GJ") and AUD $6.00/GJ for the first 10 years following the Central Closing Date, and for the following 5 years, respectively, with such prices to be escalated in accordance with the Australian CPI. Between the third and fifth anniversaries of the Central Closing Date, inclusive, the Company may seek from Central a one-time payment (the "Bonus Discharge Amount") corresponding to the present value, assuming an annual discount rate of 10%, of any expected remaining bonus payments in exchange for foregoing future bonus payments. If the Company receives the Bonus Discharge Amount, bonus payments and the Bonus Discharge Amount together may not exceed AUD $7.0 million. The Company also retained its rights to receive any and all bonuses (the "Mereenie Bonus") payable by Santos Ltd ("Santos") and contingent upon production at the Mereenie oil and gas field achieving certain threshold levels. The Mereenie Bonus was established in fiscal year 2011 pursuant to the terms of the

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asset swap agreement between the Company and Santos for the sale of the Company's interest in Mereenie to Santos and the Company's purchase of the interests of Santos in the Palm Valley and Dingo gas fields. The Company has not recognized a contingent asset related to the Bonus Discharge Amount or Mereenie Bonus, as such amounts are not reasonably assured. For additional information, see Note 3.

Note 3 - Discontinued Operations

As discussed in detail in Note 2, on March 31, 2014, pursuant to the Sale Deed, the Company completed the sale of Palm Valley and Dingo to Central PV. The assets of Palm Valley and Dingo were previously reported under the MPA segment, accordingly, results of operations associated with this sale were reclassified to discontinued operations for fiscal year 2014. Summarized results of the Company's discontinued operations are as follows:

	June 30,	
	2015	2014
	(In thousands)	
Revenue	$—	$814
Loss from discontinued operations, net of tax	$—	$(4,461)

As of June 30, 2014, the gain on disposal of discontinued operations can be summarized as follows:

	June 30, 2014 (In thousands)
Assets and liabilities sold:	
Property and equipment, net	$(10,100)
Deferred income taxes	(7,217)
Goodwill allocated to the disposal group	(1,000)
Asset retirement obligations	4,457
Purchase price adjustments	743
Total assets and liabilities of discontinued operations	(13,117)
Consideration:	
First cash installment - received on Central Closing Date	13,859
Second cash installment - received on April 15, 2014	4,695
Stock of Central	19,147
Total consideration	37,701
Reclassification of foreign currency translation gains to earnings upon sale of foreign subsidiary	5,767
Transaction costs	(339)
Gain on disposal of discontinued operations, net of tax	$30,012

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Note 4 - Securities Available-for-Sale

The following table presents the amortized cost, gross unrealized gains, gross unrealized losses and fair market value of available-for-sale equity securities as follows:

	June 30, 2015			
	Amortized cost	Gross unrealized gains	Gross unrealized losses	Fair value
	(In thousands)			
Equity securities	$19,147	$—	$(14,917)	$4,230

	June 30, 2014			
	Amortized cost	Gross unrealized gains	Gross unrealized losses	Fair value
	(In thousands)			
Equity securities	$19,339	$—	$(7,404)	$11,935

Subsequent to June 30, 2015, to meet its needs for working capital, the Company began the process of selling its investment in Central. Proceeds from sales of portions of the Company's investment in Central were well below the investment's amortized cost, and the Company could no longer maintain its ability to hold the entire investment for a period of time to allow the investment to recover. As such, the Company determined that unrealized losses related to its investment in Central were other-than-temporary, and recognized an impairment loss in the amount of $14.9 million. Also, during the year ended June 30, 2015, the Company realized a loss on the sale of its other investment in securities available-for-sale in the amount of $171 thousand. No other-than-temporary impairment or losses related to securities available-for-sale were recorded in the consolidated statement of operations for the year ended June 30, 2014.

Note 5 - Debt

Long-Term Loan. On September 17, 2014, the Company, through its wholly owned subsidiary NP, entered into a senior secured revolving loan facility (the "Revolving Loan Facility") with West Texas State Bank ("WTSB"). The Revolving Loan Facility had a floating interest rate based on prime rate with a floor rate of 3.25%, with interest payable quarterly, a maturity of September 30, 2015, and a total available borrowing limit of $8.0 million, of which $5.5 million was drawn as of June 30, 2015, when the Company entered into an amendment to the Revolving Loan Facility whereby the Revolving Loan Facility was converted into a single term loan (the "Term Loan"). The maturity of the Term Loan was extended to June 30, 2020 and bears interest at prime rate plus 1.50% with an interest rate floor of 4.75%. The Term Loan is secured by substantially all of NP's assets and a guarantee of Magellan secured by a pledge of its membership interest in NP. During the first twelve months of the Term Loan, only monthly interest payments are payable. Principal is amortized over its remaining four year term. Magellan and NP under the terms of the Term Loan, are subject to certain restrictive covenants customary in similar loan agreements. At June 30, 2015, the Company was in compliance with all such covenants.

Scheduled annual principal payments for the Term Loan are as follows:

	Total
	(In thousands)
Payable in fiscal year:	
2016	$—
2017	1,375
2018	1,375
2019	1,375
2020	1,375
Total	$5,500

During the year ended June 30, 2014, the outstanding principal of a $1.7 million note payable by NP, re-issued in January 2011 (the "Note Payable"), was fully amortized. The variable interest rate of the Note Payable was based upon the Wall Street Journal Prime Rate (the "Index") plus 1.00%, subject to a floor rate of 6.25%. Under the Note Payable, NP was subject to

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certain customary financial and restrictive covenants. The Note Payable was collateralized by a first mortgage and an assignment of production from Poplar and was guaranteed by Magellan up to $6.0 million, not to exceed the amount of the principal owed.

Note 6 - Asset Retirement Obligations

The estimated valuation of asset retirement obligations ("AROs") is based on the Company's historical experience and management's best estimate of plugging and abandonment costs by field. Assumptions and judgments made by management when assessing an ARO include: (i) the existence of a legal obligation; (ii) estimated probabilities, amounts, and timing of settlements; (iii) the credit-adjusted risk-free rate to be used; and (iv) inflation rates. Accretion expense is recorded under depletion, depreciation, amortization, and accretion in the consolidated statements of operations. If the recorded value of ARO requires revision, the revision is recorded to both the ARO and the asset retirement capitalized cost.

The following table summarizes the asset retirement obligation activity for the fiscal years ended:

	June 30,	
	2015	2014
	(In thousands)	
Fiscal year opening balance	$2,873	$6,879
Liabilities assumed	—	7
Accretion expense	171	367
Sale of assets [1]	(346)	(4,457)
Revision to estimate	—	—
Effect of exchange rate changes	(51)	77
Fiscal year closing balance	2,647	2,873
Less current asset retirement obligations	—	397
Long term asset retirement obligations	$2,647	$2,476

[1] In fiscal 2015 the Company sold its 40% interest in PEDL 126, the exploration license that contains the Markwells Wood-1 wellbore. By selling the license and the wellbore, the Company was able to eliminate its current asset retirement obligation related to the wellbore. In fiscal 2014, the Company sold its Amadeus Basin assets.

Note 7 - Fair Value Measurements

The Company follows authoritative guidance related to fair value measurement and disclosure, which establishes a three level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement using market participant assumptions at the measurement date. A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The three levels are defined as follows:

- Level 1: Quoted prices in active markets for identical assets.
- Level 2: Significant other observable inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant inputs to the valuation model are unobservable inputs.

The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and the consideration of factors specific to the asset or liability. The Company's policy is to recognize transfers in or out of a fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Company has consistently applied the valuation techniques discussed above for all periods presented. During the years ended June 30, 2015, and 2014, there have been no transfers in or out of Level 1, Level 2, or Level 3.

Assets and liabilities measured on a recurring basis

The Company's financial instruments exposed to concentrations of credit risk primarily consist of cash and cash equivalents. The carrying values for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities reflect theses items' cost, which approximates fair value based on the timing of the anticipated cash flows and current market

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conditions. The recorded value of the Term Loan (see Note 5 - Debt), approximates fair value due to its variable interest rate structure.

The following table presents items required to be measured at fair value on a recurring basis by the level in which they are classified within the valuation hierarchy as follows:

	June 30, 2015			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Securities available-for-sale	$4,230	$—	$—	$4,230
Liabilities:				
Contingent consideration payable	$—	$—	$—	$—

	June 30, 2014			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Securities available-for-sale	$11,935	$—	$—	$11,935
Liabilities:				
Contingent consideration payable	$—	$—	$1,852	$1,852

The contingent consideration payable is a standalone liability that is measured at fair value on a recurring basis for which there is no available quoted market price, principal market, or market participants. The inputs for this instrument are unobservable and therefore classified as Level 3 inputs. The calculation of this liability is a significant management estimate and uses drilling and production projections based in part on the Company's reserve report for NP to estimate future production bonus payments and a discount rate that is reflective of the Company's credit adjusted borrowing rate.

Inputs are reviewed by management on an annual basis or more frequently as deemed appropriate, and the liability is estimated by converting estimated future production bonus payments to a single net present value using a discounted cash flow model. Payments of future production bonuses are sensitive to Poplar's 60 days rolling gross production average. The contingent consideration payable would increase with significant production increases and/or a reduction in the discount rate.

Revisions to the fair value estimate of the contingent consideration payable are recorded in the consolidated statements of operations under fair value revision of contingent consideration payable. Accretion expense related to the contingent consideration payable is recorded in the consolidated statements of operations under net interest expense. As of June 30, 2014, the downward revisions were a result of the fact that a second production payout could not be reasonably assumed on the basis of current production estimates corresponding to the estimated proved reserves of Poplar at June 30, 2014.

The Company undertook a review of its planned drilling program at Poplar with respect to its proved undeveloped reserves as of June 30, 2015, and determined, in light of the current oil price environment and liquidity situation, to defer this drilling program for an indefinite period. Without this drilling program and the production volumes anticipated therefrom, the Company does not currently anticipate that the conditions for the payment of the contingent consideration will be met in the foreseeable future. As such, the Company has reversed the contingent consideration payable in its entirety as of June 30, 2015 in the accompanying consolidated financial statements.

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The following table presents information about significant unobservable inputs to the contingent consideration payable measured at fair value on a recurring basis for the fiscal years ended:

Description	Valuation technique	Significant unobservable inputs	June 30, 2015	2014
Contingent consideration payable	Discounted cash flow model	Discount rate	N/A	8.0%
		First production payout	N/A	June 30, 2015
		Second production payout	N/A	N/A

The following table presents a roll forward of the contingent consideration payable for the fiscal years ended:

	June 30, 2015	2014
	(In thousands)	
Fiscal year beginning balance	$1,852	$3,940
Accretion expense	36	315
Revision to estimate	(1,888)	(2,403)
Fiscal year closing balance	$—	$1,852

Assets and liabilities measured on a nonrecurring basis

The Company also utilizes fair value to perform an impairment test on its oil and gas properties and goodwill annually, or whenever events and circumstances indicate that a decline in the recoverability of their carrying values may have occurred. Fair value is estimated using expected discounted future cash flows from oil and gas properties. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are also classified within Level 3. For the fiscal year ended June 30, 2015, the Company reviewed its proved oil and gas properties and its recorded goodwill for a possible impairment as a result of the recent decline in oil prices and the quantity of reserves due to revisions related to the exclusion of the PUD reserve estimates, and concluded that an impairment allowance of $17.4 million was required to adjust the carrying value of its proved oil and gas properties to fair value and an impairment allowance of $674 thousand was required to adjust the carrying value of its goodwill at Nautilus Poplar to fair value. The qualitative factors used in our assessment include macroeconomic conditions, industry and market conditions, cost factors, and overall financial performance. The quantitative analysis performed included a review of the June 30, 2015 reserve estimates using forward commodity prices and an estimate of the differential less the liabilities for NP, and comparing the result of the analysis to the recorded carrying value of the net assets. The analysis indicated that the carrying value of the net assets exceeded the calculated value of the reserves net of liabilities, and therefore, an impairment had occurred. For the fiscal year ended June 30, 2014, no events or circumstances were identified that would indicate that an impairment of oil and gas properties or goodwill had occurred.

Note 8 - Income Taxes

The domestic and foreign components of our income (loss) from continuing operations are as follows for the fiscal years ended:

	June 30, 2015	2014
	(In thousands)	
United States	$(24,798)	$4,262
Australia	(16,403)	(11,563)
United Kingdom	(1,799)	(2,741)
Net loss from continuing operations attributable to Magellan Petroleum Corporation	$(43,000)	$(10,042)

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The following reconciles the Company's effective tax rate to the federal statutory tax rate for the fiscal years ended:

	June 30,	
	2015	2014
	(In thousands)	
Tax provision computed per federal statutory rate	$(14,620)	$(3,414)
State taxes, net of federal benefit	(1,005)	549
Foreign rate differential	908	818
Non taxable Australian revenue	—	(3,144)
Goodwill write off	—	(58)
APB 23 adjustment	9,632	—
Change in valuation allowance	2,846	3,476
Taxable dividends from subsidiaries, net of foreign tax credits	—	3,586
Foreign tax credit adjustment	(310)	(761)
Capital loss adjustment	1,493	73
Impact of rate change	189	291
Foreign currency translation differential	1,255	(434)
Stock based compensation forfeitures	545	
Contingent consideration payable write off	(630)	(710)
Other items	(303)	(272)
Consolidated income tax expense (benefit)	$—	$—

The following summarizes components of our income tax provision for the fiscal years ended:

	June 30,	
	2015	2014
	(In thousands)	
Consolidated current income tax provision	—	—
Consolidated deferred income tax provision	—	—
Consolidated income tax provision	$—	$—
The consolidated income tax provision is summarized as follows:		
Continuing operations	$—	$—
Discontinued operations	$—	$7,217
Effective tax rate for continuing operations	— %	— %

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Significant components of the Company's deferred tax assets and liabilities can be summarized as follows for the fiscal years ended:

	June 30, 2015	2014
	(In thousands)	
Deferred tax liabilities:		
Land, buildings and equipment	$—	$(4,030)
Foreign investments	(7,451)	
Other items	(128)	(157)
Total deferred tax liabilities	(7,579)	(4,187)
Deferred tax assets:		
Acquisition and development costs	365	—
Asset retirement obligations	990	923
Net operating losses, capital losses, and foreign tax credit carry forwards	18,521	13,891
United Kingdom exploration costs and net operating losses	3,639	3,851
Investments	100	2,378
Stock option compensation	2,184	2,839
Australian capitalized legal costs	116	143
Other items	141	141
Total deferred tax asset	26,056	24,166
Valuation allowance	(18,477)	(19,979)
Net long term deferred tax asset	$—	$—

For the fiscal year ended June 30, 2015, the valuation allowance decreased by $1.5 million, primarily due to recognition of the deferred tax liability related to reversal of the APB 23 position on all foreign subsidiaries net of additional book losses, including the impairment of oil and gas properties and unrealized losses due to other-than-temporary impairment on available for sale securities reclassed to the statement of operations.

The US gross deferred tax assets and liabilities as of June 30, 2015, and 2014, respectively, consist of foreign tax credits, property, plant and equipment, and stock options. The Australian deferred tax assets and liabilities as of June 30, 2015 consist primarily of unrealized capital loss, and net operating loss carry forwards. The Australian capital loss and net operating losses are carried forward indefinitely. During fiscal year 2015, the Company made a determination that it was no longer permanently invested in its foreign subsidiaries. As of June 30, 2015, the Company has estimated that it has an overall deferred tax asset of $8.6 million, net of a deferred tax liability related to the basis difference in its foreign subsidiaries of $10.9 million.

The Company has $13.7 million of net operating loss carryovers for federal income tax purposes as of June 30, 2015, of which $252 thousand is not benefited for financial statement purposes as it relates to tax deductions that deviate from compensation expense for financial statement purposes. The benefit of these excess tax deductions will not be recognized for financial statement purposes until the related deductions reduce taxes payable.

During fiscal year 2014 the Company sold its Amadeus Basin assets held by MPA, which is reported under discontinued operations. The reduction in gain reported in discontinued operations of $7.2 million for the year ended June 30, 2014 is related to the disposal of the Australian Petroleum Resource Rent Tax deferred tax asset, refer to Note 3 - Discontinued Operations.

During the year ended June 30, 2014, the Company utilized all of its available net operating loss carryforwards from the state of Montana. As a result, the Company is subject to taxation in the state of Montana based upon its apportioned income to that state, calculated using a waters edge methodology.

After reviewing all positive and negative evidence, a valuation allowance is recorded against all the net deferred tax assets in the US, Australia and the UK. As a result, the Company has recorded no deferred tax assets as of June 30, 2015.

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As of June 30, 2015, the Company remains subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction	Tax Years Subject to Examination:
US Federal	2012 - 2014
Colorado	2012 - 2014
Maine	2012 - 2014
Montana	2010 - 2014
Australia	2011 - 2014
United Kingdom	2011 - 2014

At June 30, 2015, the Company had net operating loss and foreign tax credit carry forwards for US Federal and State income tax purposes, respectively, which are scheduled to expire periodically as follows:

	Federal Net Operating Losses	State Net Operating Losses	Federal Foreign Tax Credit
	(In thousands)		
Expires:			
2017	$—	$8	$310
2018	—	3,103	—
2019	—	559	1,411
2020	—	2,212	624
2021	—	27	1,443
2022	—	13,309	3,655
2023 and thereafter	13,709	—	1,668
Total	$13,709	$19,218	$9,111

There are no uncertain tax positions that would meet the more-likely-than-not recognition threshold for the fiscal years ended June 30, 2015, or 2014.

Note 9 - Stock Based Compensation

The 2012 Stock Incentive Plan

On January 16, 2013, the Company's shareholders approved the Magellan Petroleum Corporation 2012 Omnibus Incentive Compensation Plan (the "2012 Stock Incentive Plan"). The 2012 Stock Incentive Plan replaced the Company's 1998 Stock Incentive Plan (the "1998 Stock Plan"). The 2012 Stock Incentive Plan provides for the granting of stock options, stock appreciation rights, restricted stock and/or restricted stock units, performance shares and/or performance units, incentive awards, cash awards, and other stock based awards to selected employees, including officers, directors, and consultants of the Company (or subsidiaries of the Company). The stated maximum number of shares of the Company's common stock authorized for awards under the 2012 Stock Incentive Plan is 625,000 shares plus the remaining number of shares under the 1998 Stock Plan immediately before the effective date of the 2012 Stock Incentive Plan, which was 36,054 as of January 15, 2013. The number of aggregate shares available for issuance will be reduced by 1 share for each share granted in the form of a stock option or stock appreciation right and 2 shares for each share granted in the form of any award that is not a stock option or stock appreciation right that is settled in stock. The maximum aggregate annual number of common shares or options that may be granted to one participant is 125,000, and the maximum annual number of performance shares, performance units, restricted stock, or restricted stock units that may be granted to any one participant is 62,500. The maximum term of the 2012 Stock Incentive Plan is ten years. In October 2014, the Company repurchased 189,062 options from a former executive, which options were previously granted under the Company's 1998 Stock Plan. Pursuant to the terms of the 2012 Stock Incentive Plan, the unissued shares underlying these unexercised options were added to the shares available for issuance under the 2012 Stock Incentive Plan.

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Stock Option Grants

Under the 2012 Stock Incentive Plan, stock option grants may contain vesting provisions such that they are TBOs, PBOs, or MBOs. During the fiscal year ended June 30, 2015, the Company granted 16,875 TBOs, 156,250 PBOs, and 49,998 MBOs to executives and employees. During the fiscal year ended June 30, 2014, the Company granted 77,493 TBOs, 187,500 PBOs and 187,500 MBOs to executives and employees.

Performance targets that trigger the vesting of the 156,250 PBOs granted in October 2014 include: (i) procuring a commercially viable commitment for the supply of CO_2 to a full-field CO_2-EOR development at Poplar at or below a certain price threshold (weighted 20%); (ii) preparing Poplar for a commercially viable CO_2-EOR development (weighted 40%); (iii) progressing the Company's UK operations by participation in a well in the Weald Basin (weighted 20%); and (iv) moving forward with the Farnham Dome project by both exercising one of the options related to the purchase of CO_2 at Farnham Dome and identifying an applicable oil project to utilize CO_2 from Farnham Dome (weighted 20%). The determination of whether any of these performance targets has been met is subject to a determination of the Board. As of June 30, 2015, no performance targets had been met.

The 49,998 MBOs granted in October 2014 will vest and become exercisable, subject to certain provisions related to ongoing employment and a three-year vesting period, if, at the end of any period of 90 trading days (a "Window"), (A) the closing price of the common stock as reported by NASDAQ (the "Closing Price") on each of the first 10 trading days of a Window equals or exceeds $40.00 per share; and (B) the median of the Closing Prices for the common stock during such Window equals or exceeds $40.00 per share.

Performance metrics used to measure the potential vesting of the PBOs granted in October 2013 consist of: (i) completing the drilling of the CO_2-EOR pilot program at Poplar (weighted 10%); (ii) Board approval of a full field CO_2-EOR development project at Poplar (weighted 40%); (iii) sale of substantially all of the Amadeus Basin assets (weighted 20%); (iv) approval of a farmout agreement or the ability to participate in drilling one well in the Weald Basin with internally developed funding, including proceeds from a sale of assets (weighted 20%); and (v) approval and execution of a farmout agreement for drilling one well in the Bonaparte Basin (weighted 10%). As of June 30, 2015, performance metrics (i), (iii) and (iv) had been met.

Potential vesting of the market based stock options granted in October 2013 is subject to the Company maintaining a $18.80 per share closing price for 10 consecutive trading days and median stock price of $18.80 over a period of 90 days.

During the year ended June 30, 2015, 61,849 stock options were exercised, resulting in the issuance of 34,112 shares of common stock, which number is net of shares withheld to satisfy certain employee tax and exercise price obligations. During the prior year, 34,375 stock options were exercised, resulting in the issuance of 28,877 shares of common stock, which number is net of shares withheld to satisfy certain employee tax and exercise price obligations.

During the year ended June 30, 2015, 427,969 stock options were forfeited or canceled, including 189,062 options repurchased from a former executive (see Cancellations, below). During the prior year, 16,250 stock options were canceled or forfeited.

During the year ended June 30, 2015, 12,499 stock options expired without exercise. During the prior year period, no stock options expired.

As of June 30, 2015, a total of 332,028 MBOs and PBOs had not vested, and 169,453 shares, including forfeited or canceled options, remained available for future issuance under the 2012 Stock Incentive Plan. During the fiscal year ended June 30, 2015, no options were issued outside of the 2012 Stock Incentive Plan. Options outstanding have expiration dates ranging from September 30, 2015, to January 12, 2025.

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The following table summarizes the stock option activity for the fiscal years ended:

	June 30, 2015 Number of Shares	WAEPS [1]	2014 Number of Shares	WAEPS [1]
Fiscal year beginning balance	1,311,528	$10.08	909,660	$10.90
Granted	223,123	$13.83	452,493	$8.27
Exercised	(61,849)	$8.74	(34,375)	$8.53
Forfeited/canceled	(427,969)	$9.68	(16,250)	$8.31
Expired	(12,499)	$8.90	—	$0.00
Options outstanding at end of fiscal year	1,032,334	$11.15	1,311,528	$10.08
Weighted average remaining contractual term of outstanding options		5.6 years		6.0 years

[1] Weighted average exercise price per share.

The total fair value of stock options vesting during the fiscal years ended June 30, 2015, and 2014, was $132 thousand, and $1.2 million, respectively. During the fiscal year ended June 30, 2015, 61,849 stock options were exercised for a number of 34,112 common stock shares, net of shares withheld to satisfy employee tax obligations. During the fiscal year ended June 30, 2014, 28,877 net common shares were issued in exchange for stock options exercised. Cash received from the exercise of stock options for the fiscal years ended June 30, 2015, and 2014, respectively, was $115 thousand, and $201 thousand. The following table summarizes options outstanding and exercisable as of June 30, 2015:

		Options outstanding			Options exercisable		
Range of exercise prices		Number of shares	Weighted average remaining contractual life	WAEPS [1]	Number of shares	Weighted average remaining contractual life	WAEPS [1]
$6.32 -	$8.32	273,747	8.1 years	$8.08	81,092	7.2 years	$7.98
$8.33 -	$9.44	190,622	5.0 years	$8.77	186,248	5.0 years	$8.78
$9.45 -	$11.20	198,436	1.3 years	$9.60	198,436	1.3 years	$9.60
$11.21 -	$14.56	200,779	7.4 years	$14.05	44,531	0.4 years	$12.80
$14.57 -	$19.28	168,750	5.1 years	$17.22	168,750	5.1 years	$17.22
		1,032,334	5.6 years	$11.15	679,057	3.9 years	$11.29
Aggregate intrinsic value		$—			$—		

[1] Weighted average exercise price per share.

The fair value of shares issued under the 2012 Stock Incentive Plan were estimated using the following weighted-average assumptions for the fiscal years ended:

	June 30, 2015 TBOs	PBOs [1]	MBOs [2]	2014 TBOs	PBOs [1]	MBOs [2]
Number of options	16,875	156,250	49,998	77,493	187,500	187,500
Weighted-average grant date fair value per share	$3.73	$7.13	$9.39	$4.79	$4.50	$5.52
Expected dividend	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Forfeiture rate	23 %	15 %	15 %	— %	— %	— %
Risk free interest rate	1.5%	1.7 % - 1.7%	2.4%	1.3 %	1.5 % - 1.7%	2.8%
Expected life (years)	6.0	5.3 - 5.4	3.2 - 3.9	6.0	0.4 - 1.6	2.6

Expected volatility (based on historical price)	57.4%	53.6 % - 54.1%	64.4%	62.1 %	61.7 % - 61.9%	66.6%

(1) The terms related to these PBOs were estimated using an average probabilistic weighted method.
(2) The Company assumed MBOs will be voluntarily exercised at the midpoint of vesting, and the contractual term.

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Stock Compensation Expense

The Company recorded $891 thousand and $2.0 million of stock compensation expense for the fiscal years ended June 30, 2015, and 2014, respectively. The $891 thousand of stock compensation expense for the year ended June 30, 2015 consisted of expense amortization related to prior period awards of $555 thousand, expense amortization related to current period option grants of $708 thousand, and stock awards and forfeitures as described below.

Stock based compensation is included under general and administrative expense in the consolidated statements of operations. At June 30, 2015, there was a total of $0.9 million in unrecognized stock compensation expense related to stock options granted. This cost is expected to be recognized over a weighted-average period of 1.4 years. The amount of unrecognized compensation expense noted above does not necessarily represent the amount that will ultimately be realized by the Company in its consolidated statement of operations. During the fiscal year ending June 30, 2016, it is expected that an additional 20,624 stock options will vest.

Stock Awards

In connection with certain executive promotions effective on October 31, 2014, the Board’s Compensation, Nominating and Governance Committee (the “CNG Committee”) established a new 2015 incentive compensation program that included grants of an aggregate of 12,500 shares of restricted stock under the 2012 Stock Incentive Plan to the Company's three senior executives and 6,250 shares of restricted stock under the 2012 Stock Incentive Plan to the Chairman of the Board. Total compensation expense from the issuance of restricted stock to executives for the year ended June 30, 2015, was $79 thousand.

The Company's director compensation policy is designed to provide the Company's non-employee directors with a portion of their annual base Board service compensation in the form of equity. On July 1, 2014, the Company issued a total of 12,041 shares of its Common Stock to non-employee directors and one board-observer pursuant to this policy and the 2012 Stock Incentive Plan. Pursuant to the compensation policy, one director elected to apply his annual compensation to the exercise of a portion of his previously awarded and vested options in lieu of receiving a share award, resulting in the issuance of an additional 2,734 shares upon exercise. Total compensation expense from the issuance of non-employee director compensation for the year ended June 30, 2015, was $264 thousand.

Forfeitures

During the year ended June 30, 2015, 238,907 unvested stock options and 17,500 unvested shares of restricted stock that were previously granted were forfeited. The forfeiture of unvested options and unvested restricted stock resulted in the reversal of previously recorded compensation expense of $648 thousand and $67 thousand, respectively, which was recorded as an offset to general and administrative expense during the year ended June 30, 2015 in the accompanying consolidated statement of operations.

Cancellations

On October 10, 2014, Magellan entered into an Options and Stock Purchase Agreement (the "Agreement") with William H. Hastings, a former executive officer and director of the Company and a beneficial owner of more than 5% of the Company’s Common Stock as of October 10, 2014. The Agreement provided for the repurchase by the Company from Mr. Hastings of 31,250 shares of the Company’s Common Stock and options to acquire 189,062 shares of the Company’s Common Stock. The gross proceeds that were paid to Mr. Hastings on October 17, 2014, pursuant to the Agreement totaled $1.4 million (the "Proceeds") and were subject to applicable tax withholdings. Of the Proceeds, $983 thousand related to the repurchase of the options, which amount was subject to applicable withholding tax withheld from and remitted on behalf of the former executive in the amount of $318 thousand. The Company canceled the 189,062 repurchased options and, pursuant to the terms of the 2012 Stock Incentive Plan, added the unissued shares underlying these unexercised options to the shares available for issuance under the 2012 Stock Incentive Plan. Of the Proceeds, the remaining $462 thousand related to the repurchase of the shares of Common Stock. See Note 11 - Stockholders' Equity for further detail.

Note 10 - Preferred Stock
The Company's certificate of incorporation provides for the issuance of up to 50.0 million preferred shares. Pursuant to the Series A Purchase Agreement discussed below, 28.0 million of the total authorized preferred shares was allocated to the Series A Preferred Stock class.

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Series A Convertible Preferred Stock Financing

On May 10, 2013, the Company entered into a Series A Convertible Preferred Stock Purchase Agreement (the "Series A Purchase Agreement") with One Stone Holdings II LP ("One Stone"), an affiliate of One Stone Energy Partners, L.P. Pursuant to the terms of the Series A Purchase Agreement, on May 17, 2013 (the "Closing Date"), the Company issued to One Stone 19,239,734 shares of Series A Convertible Preferred Stock, par value $0.01 per share (the "Series A Preferred Stock"), at a purchase price of $1.22149381 per share (the "Purchase Price"), for aggregate proceeds of approximately $23.5 million. Subject to certain conditions, each share of Series A Preferred Stock and any related unpaid accumulated dividends are convertible into one share of the Company's Common Stock, par value $0.01 per share (the "Common Stock"), at an initial conversion price equal to the Purchase Price. As a result of the reverse stock split on July 10, 2015, the conversion price was adjusted to reflect the ratio of pre-split common shares outstanding to post-split common shares outstanding multiplied by the Purchase Price, or $9.77586545 per share (the "Adjusted Conversion Price").

The Series A Purchase Agreement also includes the following key terms:

- Dividends. Holders of Series A Preferred Stock are entitled to a dividend equivalent to 7.0% per annum on the face value, which is the Purchase Price plus any accumulated unpaid dividends, payable quarterly in arrears. Dividends are generally payable in kind ("PIK") (in the form of additional shares of Series A Preferred Stock) or in cash, at the Company's option.
- Conversion. Each share of Series A Preferred Stock is convertible at any time, at the holder's option, into one share of Common Stock, based on an initial face amount and conversion price equal to the Purchase Price. The Series A Preferred Stock is entitled to customary anti-dilution protections.
- Voting. The Series A Preferred Stock is entitled to vote on an as-converted basis with the Common Stock.
- Forced Conversion. At any time after the third anniversary of the Closing Date, the Company will have the right to cause the holders to convert all, but not less than all, of the shares of Series A Preferred Stock into shares of Common Stock, if, among other conditions: (i) the average per share price of Common Stock equals or exceeds 200% of the Conversion Price for a period of 20 out of 30 consecutive trading days, (ii) the average daily trading volume of shares of Common Stock exceeds an amount equal to the number of shares of Common Stock issuable upon the conversion of all outstanding shares of Series A Preferred Stock divided by 45, and (iii) the resale of shares of Common Stock into which such shares are converted is covered by an effective shelf registration statement, or such shares of Common Stock can be sold under Rule 144 under the US Securities Act of 1933, as amended (the "Securities Act").
- Redemption. At any time after the third anniversary of the Closing Date, and upon 30 days prior written notice, the Company may elect to redeem all, but not less than all, shares of Series A Preferred Stock for an amount equal to the greater of (i) the closing sale price of the Common Stock on the date the Company delivers such notice multiplied by the number of shares of Common Stock issuable upon conversion of the outstanding Series A Preferred Stock, and (ii) a cash payment that, when considering all cash dividends already paid, allows the holders of Series A Preferred Stock to achieve a 20% annualized internal rate of return on the then outstanding Series A Preferred Stock. The holders of Series A Preferred Stock will have the right to convert the Series A Preferred Stock into shares of Common Stock at any time prior to the close of business on the redemption date.
- Change in Control. In the event of a Change in Control (as defined in the Certificate of Designations) of the Company, holders of Series A Preferred Stock will have the option to (i) convert Series A Preferred Stock into Common Stock immediately prior to the Change in Control, (ii) in certain circumstances, receive stock or securities in the acquirer of the Company having substantially identical terms as those of the Series A Preferred Stock, or (iii) receive a cash payment that, when considering all cash dividends already paid, allows the holders of Series A Preferred Stock to achieve a 20% annualized internal rate of return on the then outstanding Series A Preferred Stock.

The Company has determined that a Change in Control (as defined in the Certificate of Designations) is not solely within the Company's control, and therefore the Series A Preferred Stock is presented in the consolidated balance sheets under temporary equity, outside of permanent equity.

- Liquidation. Upon a liquidation event, holders of Series A Preferred Stock are entitled to a non-participating liquidation preference per share of Series A Preferred Stock equal to (i) 115% of the Purchase Price until the second anniversary of the Closing Date, (ii) 110% of the Purchase Price after the second anniversary of the Closing Date until the third anniversary of the Closing Date, (iii) 105% of the Purchase Price after the third anniversary of the Closing Date until the fourth anniversary of the Closing Date, and (iv) thereafter, at the Purchase Price, plus, in each case, any accrued and accumulated dividends on such share.

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- Ranking. Series A Preferred Stock ranks senior to Common Stock with respect to dividend rights and rights on liquidation, winding up, and dissolution.
- Board Representation. For so long as One Stone owns at least 15% or 10% of the fully diluted shares of Common Stock (assuming full conversion of the Series A Preferred Stock), the holders of a majority of the then outstanding shares of Series A Preferred Stock have the right to appoint two members or one member, respectively, to the Company's Board. These directors are not subject to director elections by the holders of Common Stock at the Company's annual meetings of shareholders.
- Minority Veto Rights. For so long as One Stone owns at least 10% of the fully diluted Common Stock (assuming full conversion of the Series A Preferred Stock), the holders of a majority of the then outstanding shares of Series A Preferred Stock will hold veto rights with respect to (i) capital expenditures greater than $15.0 million that are not provided for in the then-current annual budget; (ii) certain related-party transactions; (iii) changes to the Company's principal line of business; and (iv) an increase in the size of the Board to a number greater than 12.

The Series A Purchase Agreement and a related separate Registration Rights Agreement also include the following key terms:

- Standstill. For a period of two years following the date of the Series A Purchase Agreement, One Stone is generally prohibited from (i) acquiring direct or beneficial control of any additional equity securities of the Company or any rights thereto; (ii) making, or in any way participating in, directly or indirectly, any solicitation of proxies to vote in any election contest or initiate, propose or otherwise solicit stockholders of the Company for approval of any stockholder proposals; (iii) participating in or forming any voting group or voting trust with respect to any voting securities of the Company; and (iv) seeking to influence, modify, or control management, the Board, or any business, policies, or actions of the Company. Until such time as One Stone no longer holds any Series A Preferred Stock, One Stone is prohibited from engaging, directly or indirectly, in any short selling of the Common Stock. On August 3, 2015, via the First Amendment to the Series A Convertible Preferred Stock Purchase Agreement (the "Series A First Amendment"), Magellan and One Stone agreed to amend and extend the standstill provisions of the Series A Purchase Agreement to December 31, 2015. See Note 18 - Subsequent Events for further information.
- Registration Rights. Holders of Series A Preferred Stock are entitled to resale registration rights with respect to the shares of Common Stock issuable upon conversion of the Series A Preferred Stock.

The Company has analyzed the embedded features of the Series A Preferred Stock and has determined that none of the embedded features is required under US GAAP to be bifurcated from the Series A Preferred Stock and accounted for separately as a derivative. The Company recorded the transaction by recognizing the fair value of the Series A Preferred Stock at the time of issuance in the amount of $23.5 million. The Company will accrete the Series A Preferred Stock to the redemption value if events or circumstances indicate that redemption is probable.

For the fiscal years ended June 30, 2015, and 2014, respectively, the Company recorded preferred stock dividends of $1.7 million and $1.7 million, and accrued dividends in the amount of $0 and $429 thousand related to the Series A Preferred Stock. The preferred stock dividends for the nine months ended June 30, 2015 were paid in kind. Accordingly, the value of these dividends of $1.3 million was recorded and added to the preferred stock balance on the Company's balance sheet at June 30, 2015. For the fiscal year ended June 30, 2014, the value of accrued dividends paid in kind of $201 thousand and dividends paid in kind of $837 thousand was recorded and added to the preferred stock balance on the Company's balance sheet at June 30, 2014. For the fiscal year ended June 30, 2013, the Company recorded accretion in the amount of $202 thousand to reflect the initial estimated fair value at which the preferred stock was recorded.

The following table summarizes the Series A Preferred Stock activity for the fiscal years ended:

	June 30,			
	2015		2014	
	Number of shares issued	Amount	Number of shares issued	Amount
	(In thousands, except share amounts)			
Fiscal year opening balance	20,089,436	$24,539	19,239,734	$23,501
	—	—	164,607	201

PIK dividend shares issued, for previously accrued dividend				
Current year PIK dividends shares issued	1,073,261	1,311	685,095	837
Fiscal year closing balance	21,162,697	$25,850	20,089,436	$24,539

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Note 11 - Stockholders' Equity
Reverse Stock Split

On July 10, 2015, the Company filed an amendment to its articles of incorporation to effect a 1 for 8 reverse stock split of its common stock, effective July 10, 2015. All share and per share amounts relating to the common stock, stock options to purchase common stock, including the respective exercise prices of each such option, and the conversion ratio of the Series A Preferred Stock included in the financial statements and footnotes have been retroactively adjusted to reflect the reduced number of shares resulting from this action. Market conditions tied to stock price targets contained within MBOs were similarly adjusted. The par value and the number of authorized, but unissued, shares remain unchanged following the reverse stock split. No fractional shares will be issued following the reverse stock split and the Company has paid cash in lieu of any fractional shares resulting from the reverse stock split.

Treasury Stock
On September 24, 2012, the Company announced that its Board had approved a stock repurchase program authorizing the Company to repurchase up to a total value of $2.0 million in shares of its Common Stock. During November 2012, the Company repurchased 18,692 shares pursuant to this program. As of June 30, 2014, $1.9 million in shares of Common Stock remained authorized for repurchase under this program. The authorization expired on August 21, 2014, with no further repurchases of stock.
On October 10, 2014, Magellan repurchased 31,250 shares from William H. Hastings, a former Company executive, pursuant to an Options and Stock Purchase Agreement. See Note 9 - Stock Based Compensation for further details.
On July 1, 2014, upon the vesting of 18,750 shares of restricted stock previously granted to executives of the Company and pursuant to the tax withholding provisions of the Company's restricted stock award agreements, the Company withheld on a cashless basis 5,981 shares to settle withholding taxes. The withheld shares were immediately canceled.
On January 14, 2013, the Company entered into a Collateral Purchase Agreement (the "Collateral Agreement") with Sopak AG, a Swiss subsidiary of Glencore International plc ("Sopak"), pursuant to which the Company agreed to purchase: (i) 1,158,080 shares of the Company's Common Stock, (ii) a warrant granting Sopak the right to purchase from the Company an additional 543,478 shares of Common Stock, and (iii) a Registration Rights Agreement, dated as of June 29, 2009, and amended as of October 14, 2009, and June 23, 2010, between the Company, Young Energy Prize S.A., a Luxembourg corporation ("YEP"), and ECP Fund, SICAV-FIS, a Luxembourg corporation ("ECP"), which is a subsidiary of Yamalco Investments Limited, a Cyprus company ("Yamalco"), for a purchase price of $10.0 million. The Collateral Agreement was subsequently amended on January 15, 2013, and completed on January 16, 2013. The Company accounted for the Collateral Agreement by allocating the purchase price of $10.0 million to the fair value of the warrant, which was estimated at $0.8 million, and the remaining $9.2 million to the purchase of the 1,158,080 shares of Common Stock, resulting in a value per share of $7.944 for the shares of Common Stock purchased. YEP, ECP, and Yamalco are entities affiliated with Nikolay V. Bogachev, a former director of the Company.

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All repurchased common stock shares are currently being held in treasury at cost, including direct issuance cost. The following table summarizes the Company's treasury stock activity for the fiscal years ended:

	June 30, 2015		2014	
	Number of shares issued	Amount	Number of shares issued	Amount
	(In thousands, except share amounts)			
Fiscal year opening balance	1,178,139	$9,344	1,176,772	$9,333
Shares repurchased from former executive	31,250	462	—	—
Net shares repurchased for employee tax and option exercise price obligations related to the vesting of restricted stock and the exercise of employee stock options	5,981	104	1,367	11
Cancellation of shares repurchased	(5,981)	(104)	—	—
Fiscal year closing balance	1,209,389	$9,806	1,178,139	$9,344

Retired Warrant

The Company formally retired the warrant purchased from Sopak during its fiscal year ended June 30, 2013, pursuant to the Collateral Agreement described above. The fair value of the warrant was estimated using the Black-Scholes-Merton pricing model and determined to be approximately $0.8 million, which was included as a reduction of additional paid in capital.

Assumptions used in estimating the fair value of the warrant included: (i) the Common Stock market price on the repurchase date of $7.20 per share; (ii) the warrant exercise price of $9.20 per share; (iii) an expected dividend of $0; (iv) a risk free interest rate of 0.2%; (v) a remaining contractual term of 1.5 years; and (vi) an expected volatility based on historical prices of 60.8%.

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Note 12 - (Loss) Earnings Per Share

The following table summarizes the computation of basic and diluted (loss) earnings per share for the fiscal years ended:

	June 30, 2015	2014
	(In thousands, except share and per share amounts)	
Loss from continuing operations, net of tax	$(43,411)	$(10,042)
Preferred stock dividend	(1,740)	(1,696)
Net loss from continuing operations, including preferred stock dividends	(45,151)	(11,738)
Net income from discontinued operations	—	25,551
Net loss attributable to non-controlling interest in subsidiary	411	—
Net income (loss) attributable to common stockholders	$(44,740)	$13,813
Basic weighted-average shares outstanding	5,710,288	5,671,603
Add: dilutive effects of in-the-money stock options and non-vested restricted stock grants [(1)]	—	—
Diluted weighted-average common shares outstanding	5,710,288	5,671,603
Basic net (loss) earnings per common share:		
Net loss from continuing operations attributable to Magellan Petroleum Corporation, including preferred stock dividends [(2)]	$(7.83)	$(2.07)
Net income from discontinued operations	$0.00	$4.51
Net (loss) income attributable to common stockholders	$(7.83)	$2.44
Diluted net (loss) earnings per common share		
Net loss from continuing operations attributable to Magellan Petroleum Corporation, including preferred stock dividends[(2)]	$(7.83)	$(2.07)
Net income (loss) from discontinued operations	$0.00	$4.51
Net (loss) income attributable to common stockholders	$(7.83)	$2.44

[(1)] All diluted earnings per share calculations are dictated by the results from continuing operations; accordingly there were no dilutive effects on earnings per share in the periods presented since all such periods had a net loss from continuing operations.

[(2)] Loss from continuing operations is reduced by the contractual amount of Preferred stock dividends that must be expensed for the current period.

There is no dilutive effect on earnings per share in periods with net losses from continuing operations. Stock options or shares of Common Stock issuable upon the conversion of the Series A Preferred Stock were not considered in the calculation of diluted weighted average common shares outstanding, as they would be anti-dilutive. Potentially dilutive securities excluded from the calculation of diluted shares outstanding in fiscal years with net losses from continuing operations are as follows:

	June 30, 2015	2014
In-the-money stock options	27,673	65,723
Non-vested restricted stock	25,000	56,250
Common shares issuable upon conversion of Series A Preferred Stock	2,644,278	2,510,174
.	2,696,951	2,632,147

Note 13 - Segment Information

The Company conducts its operations through three wholly owned subsidiaries: NP, which operates in the US; MPUK, which includes our operations in the UK; and MPA, which includes our operations in Australia. Oversight for these subsidiaries is provided by Corporate which is treated as a cost center. Due to the sale of the Amadeus Basin assets held by MPA, results of operations related to Palm Valley and Dingo are included in results of operations from discontinued operations.

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The following table presents segment information for the fiscal years ended:

	June 30, 2015	2014
	(In thousands)	
Revenue from NP oil production	$4,459	$7,601
Net income (loss) from continuing operations:		
NP [1]	$(19,092)	$1,828
MPA	(16,404)	(934)
MPUK	(1,799)	(2,585)
Corporate	(6,139)	(8,351)
Inter-segment eliminations	23	—
Consolidated net losses from continuing operations	$(43,411)	$(10,042)
Assets:		
NP	$37,130	$48,161
MPA	4,593	14,215
MPUK [2]	2,373	7,156
Corporate	79,474	88,249
Inter-segment eliminations [3]	(76,870)	(76,346)
Consolidated assets	$46,700	$81,435
Expenditures for additions to long lived assets:		
NP	$8,795	$20,334
MPUK	275	526
Corporate	3	63
Consolidated expenditures for long lived assets	$9,073	$20,923

[1] The downward revision of the contingent consideration payable during the fiscal year ended June 30, 2015, resulted in $1.9 million of other income associated with our NP segment, refer to Note 7 - Fair Value Measurements.
[2] Refer to Note 20 - Oil and Gas Activities (Unaudited) for disclosures relating to non-cash charges to capitalized costs.
[3] Asset inter-segment eliminations are primarily derived from investments in subsidiaries.

The following table summarizes other significant items for the fiscal years ended:

	June 30, 2015	2014
	(In thousands)	
Depletion, depreciation, amortization, and accretion:		
NP	$1,001	$977
Corporate	148	146
Consolidated depletion, depreciation, amortization, and accretion	$1,149	$1,123
Lease operating:		
NP	$5,089	$6,257
Exploration:		
NP	$1,079	$541
MPA	91	436
MPUK	393	2,507
Consolidated exploration	$1,563	$3,484

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Note 14 - Commitments and Contingencies

Operating leases. The following table summarizes the Company's future minimum rental commitments under non-cancelable operating leases, net of guaranteed sublease income, as of June 30, 2015:

	Total (In thousands)
Amounts payable in fiscal year:	
2016	$173
2017	177
2018	74
Thereafter	—
Total	$424

Rent expense, recorded gross of sublease income in the accompanying consolidated statements of operations, for each of the years ended June 30, 2015, and 2014, was $0.3 million and $0.3 million, respectively.

Contingent production payments. In September 2011, the Company entered into a Purchase and Sale Agreement (the "Nautilus PSA") among the Company and the non-controlling interest owners of NP for the Company's acquisition of the sellers' interests in NP. The Nautilus PSA provides for potential future contingent production payments, payable by the Company in cash to the sellers, of up to a total of $5.0 million if certain increased average daily production rates for the underlying properties are achieved. J. Thomas Wilson, a director and chief executive officer of the Company, has an approximate 52% interest in such contingent payments. See Note 7 - Fair Value Measurements above for information regarding the estimated discounted fair value of the future contingent consideration payable related to the Nautilus PSA.

Sopak Collateral Agreement. The Company has estimated that there is the potential for a statutory liability of approximately $1.7 million and $1.6 million as of June 30, 2015, and 2014, respectively, related to US Federal tax withholdings and related penalties and interest related to the Collateral Agreement described in Note 11 - Stockholders' Equity. As a result, we have recorded a total liability of $1.7 million and $1.6 million as of June 30, 2015, and 2014, respectively, under accrued and other liabilities in the consolidated balance sheets included in this report. The Company has a legally enforceable right to collect from Sopak any amounts owed to the IRS as a result of the Collateral Agreement. As a result, we have recorded a corresponding receivable of $1.7 million and $1.6 million as of June 30, 2015, and 2014, respectively, under prepaid and other assets in the accompanying consolidated balance sheets.

Celtique Litigation. On March 3, 2015, MPUK received a claim form and particulars of claim that was issued in the High Court of Justice, Queen’s Bench Division, Commercial Court in London, England on February 26, 2015, pursuant to which Celtique Energie Weald Limited ("Celtique") as the claimant seeks, among other things, a declaration that MPUK’s 50% equal co-ownership rights with Celtique in PEDLs 231, 234 (within which license area the Broadford Bridge-1 well site is located), and 243 in the central Weald Basin in the UK have been forfeited to Celtique, and payment of £1.5 million (equivalent to $2.4 million as of June 30, 2015) for the outstanding cash calls related to the Broadford Bridge-1 well along with interest on that amount at 5% above base rate until payment (the "Celtique Claim").

On March 24, 2015 Celtique filed for summary judgment on the Celtique Claim. On April 1, 2015, MPUK filed a defense and counterclaim asserting, among other things, that the cash calls by Celtique are not valid due to the failure of Celtique as operator of the PEDLs to comply with the contractual accounting procedures, adhere to an agreed-upon drilling schedule and otherwise properly execute the parties’ development plans, and seeking to recover damages from Celtique as a result of Celtique’s unilateral actions following the purported forfeiture of the PEDL interests. On June 15, 2015, Celtique’s application for summary judgment was heard and dismissed on the basis that MPUK had a real prospect of successfully defending against the Celtique Claim. Celtique was ordered to pay MPUK’s costs of responding to the application, assessed at £60,000 (equivalent to $94 thousand as of June 30, 2015), which was paid by Celtique on June 29, 2015.

MPUK believes that it has strong defenses and intends to vigorously contest the Celtique Claim. However, due to the early stage of this matter and the uncertainty and risks inherent in litigation, the Company cannot predict an ultimate outcome. As such, a meaningful estimate of a reasonably possible loss, if any, or range of reasonably possible losses, if any, cannot be made as of the date of these consolidated financial statements. The Company has approximately \$953 thousand in capitalized costs related to these two licenses included in the accompanying consolidated balance sheet.

Utah CO2 Option. In May 2015, in accordance with an option agreement between Magellan, Utah CO2, and Savoy Energy, LLC ("Savoy"), Utah CO2 exercised the CO_2 purchase option available under the Utah CO2 Option Agreement. Exercise of the CO_2 purchase option allows Utah CO2 to negotiate in good faith and enter into a purchase agreement for CO_2 with Savoy, the key terms of which should be consistent with the terms detailed in the Utah CO2 Option Agreement, which

included a fifty year term, an attractive CO_2 price per mcf, the exclusive access to CO_2 volumes recoverable from Farnham Dome for CO_2-EOR projects in Utah, and no CO_2 purchase obligations for the first three years.
NT/P82 Seismic Survey. In June 2015, the Australian Commonwealth-Northern Territory Offshore Petroleum Joint Authority and the National Offshore Petroleum Titles Administrator ("NOPTA") approved a variation in MPA's work program commitments under the NT/P82 permit in the Bonaparte basin. In addition to retaining the requirement for geotechnical studies to be completed on or before May 12, 2015, at an estimated cost of AUD $500 thousand, the new work program commitment replaced the commitment to drill an exploration well on or before May 12, 2016, carrying an estimated cost of AUD $25 million, with the requirement to complete a minimum of 600 km^2 3-D seismic survey on or before May 12, 2016, the cost of which seismic survey is estimated at AUD $16 million. NOPTA also advised that a suspension and extension of the work requirement for the permit years ending May 12, 2015, and 2016, may be considered, and any renewal application will be expected to include plans for drilling of an exploratory well.
Petrie Engagement. In June 2015, the Special Committee engaged Petrie Partners, LLC ("Petrie") to act as its financial advisor (the "Petrie Engagement"). Under the terms of the Petrie Engagement, the Company has agreed to pay Petrie certain fees contingent upon the successful closing of certain transactions ranging from $0 to 3% of the value of such transaction, together with reimbursement of expenses. The Petrie Engagement may be terminated by either party with 5 days written notice.
Poplar CO_2-EOR Pilot Bonus. Mi3 Petroleum Engineering ("Mi3") is a Golden, Colorado, based petroleum engineering firm that advises the Company with respect to its CO_2-EOR activities, including the Company's CO_2-EOR pilot at Poplar (See Note 15 - Related Party Transactions). Pursuant to the terms of a master services contract with Mi3, in addition to contracted rates for services performed, certain contingent bonuses may become payable to Mi3. The first of these will become payable upon a decision by the Company to pursue a full-field CO_2-EOR development at Poplar and is estimated at $365 thousand as of June 30, 2015. The remainder of the bonuses are based on triggers related to project funding and full-field production rates.

Note 15 - Related Party Transactions

Davis Graham & Stubbs LLP. Milam Randolph Pharo, a Director of the Company until December 11, 2014, is currently of counsel at Davis Graham & Stubbs LLP (“DGS”), a Denver-based law firm with over 140 attorneys, of which over 65 are partners. Mr. Pharo has held that position since April 2013. Mr. Pharo has a compensation arrangement with DGS such that Mr. Pharo has an interest in the amount of fees paid by the Company to DGS for certain legal services performed by DGS for the Company. During the fiscal years ended June 30, 2015, and 2014, the Company recorded $335 thousand and $177 thousand, respectively, of legal fees related to DGS, with respect to which amounts Mr. Pharo had a compensation interest of $0 and less than $2,500, respectively.

Devizes International Consulting Limited. A director of Celtique, with which the Company co-owns equally several licenses in the UK, is also the sole owner of Devizes International Consulting Limited ("Devizes"). Devizes performs consulting related services to MPUK. The Company recorded $184 thousand and $161 thousand of consulting fees related to Devizes for the fiscal years ended June 30, 2015, and 2014, respectively.
Key Energy Services. J. Robinson West, the Chairman of the Board of Directors of the Company, also served as a non-employee director on the board of directors for Key Energy Services Inc. ("KES") until May 2014. KES performed contract drilling rig services for the Company in Poplar during the second quarter of fiscal year 2014. The total contract fees paid to KES during the fiscal years ended June 30, 2015 and 2014, were $0 and $2.2 million, respectively. As of June 30, 2015 and 2014, there were no unpaid contract fees related to KES.
Mervyn Cowie. Mervyn Cowie, a former employee of the Company's MPA subsidiary, currently serves both as a director of MPA and its subsidiaries and as a consultant to MPA. Since December 1, 2014, the recurring monthly fee payable to Mr. Cowie for his consulting services amounts to AUD $5,400.
Mi3 Petroleum Engineering. In association with its purchase of an option to acquire Farnham Dome, the Company established Utah CO2, a majority owned subsidiary having other non-controlling interest owners, one of which is MI4 Oil and Gas LLC ("MI4"). MI4 is a Colorado limited liability company majority owned by Mi3. Mi3 performs

ongoing consulting work for both Utah CO2 and other Magellan entities. During the fiscal year ended June 30, 2015, the Company recorded $1.1 million of consolidated expense related to fees payable to Mi3.

Note 16 - Employee Retention and Severance Costs
The Company is required to record charges for one-time employee severance benefits and other associated costs as incurred.

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Incentive Agreements with Chief Financial Officer

On October 12, 2015, the Company entered into a series of new incentive compensation agreements with Antoine J. Lafargue, the Company's Chief Financial Officer (the "CFO Incentive Agreements"). The CFO Incentive Agreements include i) amendments to the provisions for severance payments available to the CFO under his existing employment agreement dated October 31, 2014 (pursuant to an amendment of such employment agreement), to include provisions for the payment of up to two years' salary as severance in the event that the CFO’s employment with the Company is terminated under certain circumstances within a period ending ten months after the date on which a qualifying transaction (as generally defined below) occurs, capped at $600 thousand; ii) a restricted stock award agreement whereby a restricted stock grant was made to the CFO on October 12, 2015 totaling 62,500 shares of common stock that are to vest immediately prior to the completion of a qualifying transaction; iii) a potential cash award pursuant to a transaction incentive agreement, which cash award is contingent upon the completion of a qualifying transaction and would range from $0 to $1 million based on the market value of the Company's common stock reflected in the qualifying transaction, with the amount of cash award to be equal to $2,750 for each one cent of market value per share of the Company’s common stock reflected in the qualifying transaction above a minimum market value threshold of $1.60 per share; iv) a phantom stock award, also pursuant to the transaction incentive agreement, with payment contingent upon completion of a qualifying transaction and to be based on the value of 62,500 notional shares; and v) an override bonus agreement which provides for a potential bonus outside of the Company’s 2012 Omnibus Incentive Compensation Plan that would double the amounts payable under the awards available under ii, iii, and iv, above, in certain circumstances. For purposes of the CFO Incentive Agreements, a qualifying transaction is generally defined to mean an acquisition of more than 50% of the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors, or the sale or other disposition of greater than 95% of the value of the gross assets of the Company, in either case occurring prior to December 31, 2017. No accrual has been made in the accompanying consolidated financial statements for the CFO Incentive Agreements as amounts were contingent on the occurrence of future events and service.

Employee Retention Cash Bonus Plan

On June 5, 2015, the Compensation, Nominating and Governance Committee of the Board of Directors of the Company and the Board of Directors of the Company approved a cash bonus plan for the Company's non-executive officer employees for the purpose of retention of certain key accounting, human resource, and administrative employees through certain key milestone events (the "Employee Retention Cash Bonus Plan"). The terms of the Employee Retention Cash Bonus Plan specify payment of retention bonuses for such employees upon the achievement of the milestones, which are i) the filing of the Company's annual report on Form 10-K for the year ended June 30, 2015, and ii) the completion of a strategic transaction. The maximum bonus payable to the employees under each of the milestones is as follows: i) $168 thousand, and ii) $286 thousand, respectively. No accrual has been made in the accompanying consolidated financial statements for the Employee Retention Cash Bonus Plan as amounts were contingent on the occurrence of future events and service.

Severance and Termination Benefit Payments

On August 31, 2014, the Company provided a notice of termination to the only remaining employee of its MPA subsidiary. As a result, during the fiscal year ended June 30, 2015, the Company expensed and paid total employee-related severance costs of $475 thousand.

On March 31, 2014, the Company sold its interests in Palm Valley and Dingo to Central. Pursuant to the Sale Deed, the Company incurred severance costs payable in connection with the termination of certain MPA employees. For the fiscal year ended June 30, 2014, the Company expensed total employee-related severance costs of $1.2 million to loss from discontinued operations, net of tax, in the consolidated statement of operations.

In July 2012, the Company incurred severance costs payable in connection with the termination of the employment of certain employees pursuant to the terms of their employment agreements, $418 thousand of which were paid during the fiscal year ended June 30, 2014.

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A reconciliation of the beginning and ending liability balance for charges to the consolidated statements of operations and cash payments is as follows for the fiscal years ended:

	June 30, 2015	2014	
	Severance - Termination Benefits	Severance - Discontinued Operations	Severance - Termination Benefits
	(In thousands)		
Fiscal year beginning balance	$—	$—	$418
Charges to general and administrative expense	475	—	—
Charges to loss from discontinued operations, net of tax	—	1,210	—
Cash payments	(475)	(1,210)	(418)
Fiscal year closing balance	$—	$—	$—

Note 17 - Accumulated Other Comprehensive Income (Loss)

The following table represents the changes in components of accumulated other comprehensive (loss) income, net of tax, for the fiscal year ended:

	June 30, 2015		
	Foreign currency translation	Unrealized investment holding loss	Total
	(In thousands)		
Fiscal year opening balance	$6,144	$(8,153)	$(2,009)
Changes in comprehensive (loss) income:			
Other comprehensive (loss) income before reclassification	(2,141)	(6,294)	(8,435)
Amounts reclassified from other comprehensive loss (1)	659	15,087	15,746
Net current period other comprehensive loss	(1,482)	8,793	7,311
Fiscal year ended June 30, 2015	$4,662	$640	$5,302

(1) Reclassification consists of foreign currency translation loss on intercompany account balances of $659 thousand to earnings upon reversal of permanent investment in foreign subsidiaries, and impairment loss on securities available-for-sale of $15.1 million to earnings due to determination as other than temporary.

Note 18 - Subsequent Events

Reverse Stock Split. On July 10, 2015, pursuant to the Company's definitive proxy statement filed on June 8, 2015, the Company held a Special Meeting of Stockholders to approve an amendment to its Restated Certificate of Incorporation to effect a reverse stock split of its common stock at a ratio to be determined by the Board of Directors within a specific range set forth in the proxy statement, without reducing the number of authorized shares. The Company's shareholders approved the proposed amendment to the Restated Certificate of Incorporation, and the Board of Directors selected a reverse split ratio of one-for-eight (1:8). As a result of the reverse stock split, as of the close of business on July 10, 2015, each eight shares of common stock were converted into one share of common stock with any fractional shares being settled in cash. Immediately preceding the reverse stock split there were 55,313,647 shares of common stock issued, including 9,675,114 treasury shares. The number of shares of Series A Preferred Stock did not change as a result of the split; however, following the reverse stock split the conversion price was adjusted to reflect the split from $1.22149381 to $9.77586545. After the reverse stock split there were 6,911,921 shares of common stock issued, including 1,209,389 treasury shares.

Stock Based Compensation. On July 1, 2015, upon the vesting of 12,500 shares of restricted stock previously granted to executives of the Company and pursuant to the tax withholding provisions of the Company's restricted stock award agreements, the Company withheld on a cashless basis 2,822 shares to settle withholding taxes. The withheld shares were immediately cancelled.

On July 3, 2015, the Special Committee determined that the directors' annual stock award under the compensation policy for non-employee directors and the 2012 Stock Incentive Plan would be deferred and revisited in a few months after the strategic alternative review process has advanced further and liquidity issues have been addressed.

On September 30, 2015, 33,333 stock options expired without exercise.

Based on the activity related to our outstanding stock options and restricted stock after June 30, 2015, as of October 9, 2015, the Company had 202,786 shares, including forfeited shares, available for future issuance under the 2012 Stock Incentive Plan.

Partial Sale of Central Investment. Beginning in July 2015, the Company began selling some of its 39.5 million shares of Central on the open market as a source of liquidity. As of October 9, 2015, the Company has sold shares of Central in the open market and generated approximately AUD $1.3 million of proceeds. As of October 9, 2015, the Company continues to own approximately 27.4 million shares of Central, which at the share price as of October 9, 2015 of AUD $0.155 and foreign exchange rate of 0.72, represented approximately $3.1 million of potential liquidity.

Engagement of RFC Ambrian as financial advisor for farmout of NT/P82. In July 2015, the Company engaged RFC Ambrian as its financial advisor to run a formal bid process for the farm-out of its 100% operating interest in the NT/P82 permit in the Bonaparte basin, offshore Australia, to fund future exploration costs and recover back-costs incurred. The terms of the engagement include cash payments of $20 thousand and $80 thousand for the two initial stages of the engagement through a written offer, and a success fee upon completion of a legally binding agreement ranging from $250 thousand to 5% of the farm-out value of the agreement to the Company.

One Stone Standstill Extended to December 31, 2015. On August 3, 2015, the Company and One Stone agreed to amend and extend the standstill provisions of the Series A Purchase Agreement to December 31, 2015 via the Series A First Amendment. In addition to extending the terms of the prior standstill, One Stone agreed to be prohibited from i) depositing any securities of the Company in trust or subjecting them to any voting agreement or arrangement and ii) requesting the Company to modify or waive any provision of the standstill covenants. Certain definitions were also updated in the Series A First Amendment.

Celtique Litigation. In August 2015, pursuant to the terms of the PEDLs and as a result of the litigation initiated by Celtique discussed in Note 14 - Commitments and Contingencies - Celtique Litigation, the Company paid its share of license fees related to the three Central Weald licenses in the amount of £50,000.

Incentive Agreements with Chief Financial Officer. On October 12, 2015, the Company entered into a series of new incentive agreements with its Chief Financial Officer. For further information, please refer to Note 16 - Employee Retention and Severance Costs.

Note 19 - Supplemental Oil and Gas Information (Unaudited)

Supplemental Oil and Gas Reserve Information

The Company relies upon a combination of internal technical staff and third party consulting arrangements for reserve estimation and review. The reserve information presented below is based on estimates of net proved reserves as of June 30, 2015, and 2014, and was prepared in accordance with guidelines established by the SEC.

Reserve estimates were prepared by Hector Wills of Mi3 Petroleum Engineering, a Golden, Colorado based petroleum engineering firm, for the fiscal years ended June 30, 2015 and 2014. Reserve estimates were audited by the Company's independent petroleum engineering firm, Allen & Crouch Petroleum Engineers ("A&C") for each of the fiscal years presented. A copy of the summary reserve audit report of A&C is provided as Exhibit 99.1 to this Annual Report on Form 10-K. A&C does not own an interest in any of Magellan's oil and gas properties and is not employed by Magellan on a contingent basis.

Proved reserves are the estimated quantities of oil, gas, and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. All of the Company's estimated proved reserves are located in the US.

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Analysis of Changes in Proved Reserves

The following table sets forth information regarding the Company's estimated proved oil and gas reserve quantities. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as economic conditions change and new information becomes available.

	United States	Australia [1]	Total	
	Oil (Mbbls)	Gas (Bcf)	Oil (Mbbls)	Gas (Bcf)
Proved Reserves:				
Fiscal year ended June 30, 2013	7,368.6	11.4	7,368.6	11.4
Revision of previous estimates	(1,515.0)	—	(1,515.0)	—
Sales of minerals in place	—	(11.4)	—	(11.4)
Production	(117.9)	—	(117.9)	—
Fiscal year ended June 30, 2014	5,735.7	—	5,735.7	—
Revision of previous estimates	(3,417.1)	—	(3,417.1)	—
Production	(79.0)	—	(79.0)	—
Fiscal year ended June 30, 2015	2,239.6	—	2,239.6	—
Proved Developed Reserves:				
Fiscal year ended June 30, 2014	2,494.6	—	2,494.6	—
Fiscal year ended June 30, 2015	2,239.6	—	2,239.6	—
Proved Undeveloped Reserves:				
Fiscal year ended June 30, 2014	3,241.1	—	3,241.1	—
Fiscal year ended June 30, 2015	—	—	—	—

[1] The amount of proved reserves applicable to Australia gas reflects the amount of gas committed to specific long term supply contracts.

Revision of previous estimates. Revisions of estimates represent downward changes in previous estimates attributable to new information gained primarily from development activity, production history, and changes to the economic conditions and the financial condition of the Company at the time of each estimate. During the year ended June 30, 2015, there was a 3,417 Mbbls downward revision of estimated proved reserves. The majority of the revision relates to the removal of 3,083 Mbbls of proved undeveloped reserves from the classification of proved reserves due to the uncertainty surrounding the Company's ability to continue as a going concern and to obtain the necessary capital to develop the PUD locations. During fiscal 2015, the Company did not convert any proved undeveloped reserves to proved developed reserves. The proved undeveloped reserves as of June 30, 2014, which were attributable to a new 9-well drilling program at Poplar are in the immediate vicinity of the five wells that have been drilled for the CO_2-EOR pilot project.

Standardized Measure of Oil and Gas

The Company computes a standardized measure of future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented.

The "standardized measure" is the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service, depreciation, depletion, and amortization, and tax, and are discounted using an annual discount rate of 10% to reflect timing of future cash flows.

The assumptions used to calculate estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices, or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

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Prices. All prices used in calculation of our reserves are based upon a twelve month unweighted arithmetic average of the first day of the month price for the twelve months of the fiscal year, unless prices were defined by contractual arrangements. Prices are adjusted for local differentials and gravity and, as required by the SEC, held constant for the life of the projects (i.e., no escalation). The following table summarizes the resulting prices used for proved reserves for the fiscal years ended:

	June 30,	
	2015	2014
Oil (per Bbl)	$58.93	$86.11
Gas (per Mcf)	NA	NA

Costs. Future development and production costs are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Income taxes. Future income tax expenses are calculated by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

Discount. The present value of future net cash flows from the Company's proved reserves is calculated using a 10% annual discount rate. This rate is not necessarily the same as that used to calculate the current market value of our estimated oil and natural gas reserves.

The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves for the United States cost center only:

	Year Ended June 30,	
	2015	2014
	(In thousands)	
Future cash inflows	$131,979	$493,901
Future production costs	(85,372)	(226,464)
Future development costs	(7,021)	(23,594)
Future income tax expense	—	(73,820)
Future net cash flows	39,586	170,023
10% annual discount	(22,569)	(82,980)
Standardized measures of discounted future net cash flows	$17,017	$87,043

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A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	United States	Australia	Total
	(In thousands)		
Fiscal year ended June 30, 2013	$97,391	$10,285	$107,676
Net change in prices and production costs	(10,222)	—	(10,222)
Revisions of previous quantity estimates	(34,441)	—	(34,441)
Divestiture of reserves	—	(10,285)	(10,285)
Changes in estimated future development costs	3,161	—	3,161
Sales and transfers of oil and gas produced	(4,720)	—	(4,720)
Previously estimated development cost incurred during the period	1,723	—	1,723
Accretion of discount	14,632	—	14,632
Net change in income taxes	16,746	—	16,746
Net change in timing and other	2,773	—	2,773
Fiscal year ended June 30, 2014	87,043	—	87,043
Net change in prices and production costs (1)	(71,406)	—	(71,406)
Revisions of previous quantity estimates (2)	(54,415)	—	(54,415)
Divestiture of reserves	—	—	—
Changes in estimated future development costs	9,071	—	9,071
Sales and transfers of oil and gas produced	(440)	—	(440)
Previously estimated development cost incurred during the period	7,749	—	7,749
Accretion of discount	8,853	—	8,853
Net change in income taxes (3)	32,188	—	32,188
Net change in timing and other	(1,626)	—	(1,626)
Fiscal year ended June 30, 2015	$17,017	$—	$17,017

(1) For fiscal year 2015, there was a $71.4 million downward revision in reserve value due to the net change in prices and production costs. This change was the result of the steep decline in the WTI price, the benchmark oil price for sale of the Company's crude oil.

(2) The downward revision of $54.4 million relates to the elimination of PUDs of 3,241Mbbls from the classification as proved reserves and is discussed in greater detail above under the heading "Analysis of Changes in Proved Reserves."

(3) The increase in cash flows from the net change in income taxes represents the decrease in future income taxes as a result of the elimination of cash flows from PUD reserves.

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Note 20 - Oil and Gas Activities (Unaudited)

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	United States	Australia	United Kingdom	Total
	(In thousands)			
Fiscal year ended June 30, 2015				
Proved	$—	$—	$—	$—
Unproved	—	—	—	—
Exploration Costs	1,079	91	393	1,563
Development Costs	7,749	—	274	8,023
Total, including asset retirement obligation	$8,828	$91	$667	$9,586
Fiscal year ended June 30, 2014				
Proved	$1,729	$—	$—	$1,729
Unproved	8	—	—	8
Exploration Costs	541	436	2,507	3,484
Development Costs	21,174	—	551	21,725
Total, including asset retirement obligation	$23,452	$436	$3,058	$26,946

Net Changes in Capitalized Costs

The net changes in capitalized costs that are currently not being depleted pending the determination of proved reserves can be summarized as follows:

	United States	Australia	United Kingdom	Total
	(In thousands)			
Fiscal year ended June 30, 2015				
Fiscal year beginning balance	$19,955	$—	$1,890	$21,845
Additions to capitalized costs	8,047	—	274	8,321
Assets sold or held for sale	—	—	(680)	(680)
Reclassified to producing properties [1]	(8,973)	—	—	(8,973)
Charged to expense	—	—	(20)	(20)
Exchange adjustment	—	—	(124)	(124)
Fiscal year closing balance	$19,029	$—	$1,340	$20,369
Fiscal year ended June 30, 2014				
Fiscal year beginning balance	$496	$3,976	$1,762	$6,234
Additions to capitalized costs [2]	19,459	1,104	948	21,511
Assets sold or held for sale	—	(5,258)	—	(5,258)
Charged to expense	—	—	(733)	(733)
Exchange adjustment	—	178	(87)	91
Fiscal year closing balance	$19,955	$—	$1,890	$21,845

[1] The Company reclassified the capitalized costs for two of the five CO_2-enhanced oil recovery pilot wells from wells in progress to producing properties during the forth quarter of fiscal 2015.

[2] The Company began implementing a CO2-enhanced oil recovery pilot project at NP in the first quarter of fiscal year 2014.

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In the United Kingdom, during the third quarter of fiscal year 2015, the Company allowed a petroleum license to expire and recorded exploration expense of $20 thousand. During the fourth quarter of fiscal year 2015, the Company sold its interest in a license with a remaining capitalized cost of $0.7 million. During the third quarter of fiscal year 2014, the Company allowed petroleum exploration and development licenses in the UK to expire at the end of their term. As a result, $0.7 million of exploration expense was recorded in the consolidated statement of operations.

At June 30, 2015, the Company had no costs capitalized for exploratory wells in progress for a period of greater than one year after the completion of drilling.

Note 21 - Quarterly Financial Data (Unaudited)

The following table summarizes the unaudited quarterly financial data, including continuing (loss) income before income taxes, net (loss) income, and net (loss) income per common share for the fiscal years ended:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	June 30, 2015
	(In thousands, except per share data)				
Fiscal year ended June 30, 2015					
Revenue from oil production [1]	$1,590	$1,265	$688	$916	$4,459
Total operating expenses [2]	$4,280	$4,153	$4,863	$21,459	$34,755
Continuing operations:					
Loss from continuing operations attributable to Magellan Petroleum Corporation[3][4]	$(2,627)	$(2,715)	$(2,115)	$(35,543)	$(43,000)
Net loss per basic common share outstanding	$(0.54)	$(0.55)	$(0.45)	$(6.29)	$(7.83)
Net loss per diluted common share outstanding	$(0.54)	$(0.55)	$(0.45)	$(6.29)	$(7.83)
Attributable to common stockholders:					
Net loss	$(3,057)	$(3,145)	$(2,552)	$(35,986)	$(44,740)
Net loss per basic common share outstanding	$(0.54)	$(0.55)	$(0.45)	$(6.29)	$(7.83)
Net loss per diluted common share outstanding	$(0.54)	$(0.55)	$(0.45)	$(6.29)	$(7.83)

[1] The benchmark oil price, WTI declined significantly in the third quarter.

[2] During the fourth quarter, the company recorded an impairment of its proved oil and gas properties of $17.4 million.

[3] During the third quarter, a downward revision in the contingent consideration payable resulted in other income of $1.9 million.

[4]Loss from continuing operations increased in the fourth quarter due to the impairment of proved oil and gas properties mentioned previously, and an other-than-temporary impairment of $14.9 million related to the Company's investment in Central.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	June 30, 2014
	(In thousands, except per share data)				
Fiscal year ended June 30, 2014					
Revenue from oil production	$2,134	$1,633	$1,907	$1,927	$7,601
Total operating expenses	$5,737	$4,193	$4,927	$5,092	$19,949
Continuing operations:					
Loss from continuing operations [1]	$(3,681)	$(2,610)	$(3,072)	$(679)	$(10,042)
Net loss per basic common share outstanding	$(0.72)	$(0.53)	$(0.62)	$(0.20)	$(2.07)
Net loss per diluted common share outstanding	$(0.72)	$(0.53)	$(0.62)	$(0.20)	$(2.07)
Attributable to common stockholders:					
Net (loss) income [2]	$(5,250)	$(4,533)	$24,089	$(493)	$13,813

Net (loss) income per basic common share outstanding	$(0.93)	$(0.80)	$4.25	$(0.08)	$2.44
Net (loss) income per diluted common share outstanding	$(0.93)	$(0.80)	$4.25	$(0.08)	$2.44

(1) A downward revision of the contingent consideration payable during the fourth quarter of fiscal year 2014 resulted in $1.9 million of other income associated with our NP segment, refer to Note 7 - Fair Value Measurements for further details.

(2) During the third quarter the Company sold its Palm Valley and Dingo gas fields to Central (see Note 2 - Sale of Amadeus Basin Assets). The transaction resulted in a gain on disposal of discontinued operations, net of tax in the amount of $30.0 million.

ITEM 9: CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A: CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including resource constraints and judgments about the expected benefits of control alternatives relative to their costs, assumptions about the likelihood of future events, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the Company's fiscal quarter ended June 30, 2015, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is 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. The Company's internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- 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

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

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Management assessed the effectiveness of the Company's internal control over financial reporting as of June 30, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (1992 Framework). Based on our assessment and these criteria, we believe that internal control over financial reporting is effective as of June 30, 2015.
This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Our internal controls over financial reporting were not subject to attestation by the Company's registered public accounting firm pursuant to rules of the SEC that permit the Company to provide only management's report in this annual report.

ITEM 9B: OTHER INFORMATION

We have elected to include the following information in this Form 10-K in lieu of reporting it in a separately filed Form 8-K. This information would otherwise have been reported in a Form 8-K under the heading "Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers."
On October 12, 2015, the Company entered into a series of new incentive compensation agreements with Antoine J. Lafargue, the Company's Chief Financial Officer (the "CFO Incentive Agreements"). The CFO Incentive Agreements include i) amendments to the provisions for severance payments available to the CFO under his existing employment agreement dated October 31, 2014 (pursuant to an amendment of such employment agreement), to include provisions for the payment of up to two years' salary as severance in the event that the CFO’s employment with the Company is terminated under certain circumstances within a period ending ten months after the date on which a qualifying transaction (as generally defined below) occurs, capped at $600 thousand; ii) a restricted stock award agreement whereby a restricted stock grant was made to the CFO on October 12, 2015 totaling 62,500 shares of common stock that are to vest immediately prior to the completion of a qualifying transaction; iii) a potential cash award pursuant to a transaction incentive agreement, which cash award is contingent upon the completion of a qualifying transaction and would range from $0 to $1 million based on the market value of the Company's common stock reflected in the qualifying transaction, with the amount of cash award to be equal to $2,750 for each one cent of market value per share of the Company’s common stock reflected in the qualifying transaction above a minimum market value threshold of $1.60 per share; iv) a phantom stock award, also pursuant to the transaction incentive agreement, with payment contingent upon completion of a qualifying transaction and to be based on the value of 62,500 notional shares; and v) an override bonus agreement which provides for a potential bonus outside of the Company’s 2012 Omnibus Incentive Compensation Plan that would double the amounts payable under the awards available under ii, iii, and iv, above, in certain circumstances. For purposes of the CFO Incentive Agreements, a qualifying transaction is generally defined to mean an acquisition of more than 50% of the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors, or the sale or other disposition of greater than 95% of the value of the gross assets of the Company, in either case occurring prior to December 31, 2017. A copy of the CFO Incentive Agreements are filed as Exhibits 10.23, 10.24, 10.25, and 10.26 to this report.

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PART III

Pursuant to General Instruction G(3), the information called for by Items 10, (except for certain information concerning the executive officers of the Company set forth below) 11, 12, 13, and 14 is hereby incorporated by reference to the Company's definitive proxy statement for the 2015 annual meeting of stockholders to be filed within 120 days from June 30, 2015. Certain information concerning the executive officers of the Company is included below under Item 10: Directors, Executive Officers, and Corporate Governance of this report.

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The following table sets forth the names, ages, and positions held by the Company's executive officers. The ages of our executive officers are listed as of October 13, 2015.

Name	Age	Office Held	Length of Service as Officer
J. Thomas Wilson	63	President and Chief Executive Officer	Since September 2011
Antoine J. Lafargue	41	Senior Vice President - Chief Financial Officer, Treasurer and Corporate Secretary	Since August 2010

For further information regarding the executive officers, see the Company's definitive proxy statement for the 2015 annual meeting of stockholders to be filed within 120 days from June 30, 2015.

ITEM 11: EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information regarding executive compensation provided in the Company's definitive proxy statement for the 2015 annual meeting of stockholders to be filed within 120 days from June 30, 2015.

ITEM 12: SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item is incorporated by reference to the information regarding security ownership of certain beneficial owners and management and related stockholder matters provided in the Company's definitive proxy statement for the 2015 annual meeting of stockholders to be filed within 120 days from June 30, 2015.

ITEM 13: CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information regarding certain relationships and related transactions, and director independence provided in the Company's definitive proxy statement for the 2015 annual meeting of stockholders to be filed within 120 days from June 30, 2015.

ITEM 14: PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the information regarding principal accounting fees and services provided in the Company's definitive proxy statement for the 2015 annual meeting of stockholders to be filed within 120 days from June 30, 2015.

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PART IV

ITEM 15: EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the consolidated financial statements and notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report:

EXHIBIT NUMBER	DESCRIPTION
2.1	Purchase and Sale Agreement among Magellan Petroleum Corporation and the members of Nautilus Technical Group LLC and Eastern Rider LLC, dated as of September 2, 2011 (filed as Exhibit 2.2 to the registrant's Quarterly Report on Form 10-Q filed on November 14, 2011 and incorporated herein by reference)
2.2	Sale Agreement among Magellan Petroleum (NT) Pty Ltd, Santos QNT Pty Ltd, and Santos Limited, dated September 14, 2011 (filed as Exhibit 2.3 to the registrant's Quarterly Report on Form 10-Q filed on November 14, 2011 and incorporated herein by reference)
2.3	Share Sale and Purchase Deed dated February 17, 2014, among Magellan Petroleum Australia Pty Ltd, Magellan Petroleum (N.T) Pty. Ltd., Magellan Petroleum Corporation, Jarl Pty. Ltd., Central Petroleum PVD Pty. Ltd, and Central Petroleum Limited (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 18, 2014 and incorporated herein by reference) (Pursuant to Item 601(b)(2) of Regulation S-K, certain schedules and similar attachments have been omitted. The registrant hereby agrees to furnish supplementally a copy of any omitted schedule or attachment to the U.S. Securities and Exchange Commission upon request)
2.4	Escrow Agency Deed dated February 17, 2014, between Magellan Petroleum Australia Pty Ltd and Central Petroleum PVD Pty. Ltd. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on February 18, 2014 and incorporated herein by reference)
3.1	Restated Certificate of Incorporation as filed on May 4, 1987 with the State of Delaware, as amended by an Amendment of Article Twelfth as filed on February 12, 1988 with the State of Delaware (filed as Exhibit 4.B. to the registrant's Registration Statement on Form S-8 filed on January 14, 1999 (Registration No. 333-70567) and incorporated herein by reference)
3.2	Certificate of Amendment of Restated Certificate of Incorporation as filed on December 26, 2000 with the State of Delaware (filed as Exhibit 3(a) to the registrant's Quarterly Report on Form 10-Q filed on February 13, 2001 and incorporated herein by reference)
3.3	Certificate of Amendment of Restated Certificate of Incorporation related to Articles Twelfth and Fourteenth as filed on October 15, 2009 with the State of Delaware (filed as Exhibit 3.3 to the registrant's Quarterly Report on Form 10-Q filed on February 16, 2010 and incorporated herein by reference)
3.4	Certificate of Amendment of Restated Certificate of Incorporation related to Article Thirteenth as filed

	on October 15, 2009 with the State of Delaware (filed as Exhibit 3.4 to the registrant's Quarterly Report on Form 10-Q filed on February 16, 2010 and incorporated herein by reference)
3.5	Certificate of Amendment of Restated Certificate of Incorporation related to Article Fourth as filed on December 10, 2010 with the State of Delaware (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 13, 2010 and incorporated herein by reference)
3.6	Certificate of Designations of Series A Convertible Preferred Stock as filed on May 17, 2013 with the State of Delaware (filed as Exhibit 3.6 to the registrant's Current Report on Form 8-K filed on June 26, 2013 and incorporated herein by reference)
3.7	Certificate of Amendment to Certificate of Designations of Series A Convertible Preferred Stock as filed on August 19, 2013 with the State of Delaware (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on August 19, 2013 and incorporated herein by reference)

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3.8	Certificate of Amendment of Restated Certificate of Incorporation as filed on July 10, 2015 with the State of Delaware (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on July 10, 2015 and incorporated herein by reference)
3.9	By-Laws, as amended on June 13, 2013 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on June 18, 2013 and incorporated herein by reference)
4.1+	Registration Rights Agreement dated May 17, 2013 between Magellan Petroleum Corporation and One Stone Holdings II LP (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on June 26, 2013 and incorporated herein by reference)
10.1+	1998 Stock Option Plan (filed as Exhibit 4.A. to the registrant's Registration Statement on Form S-8 filed on January 14, 1999 (Registration No. 333-70567) and incorporated herein by reference)
10.2+	First Amendment to the 1998 Stock Option Plan dated October 24, 2007 (filed as Exhibit 10(n) to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2008 and incorporated herein by reference)
10.3+	1998 Stock Incentive Plan, as amended and restated through September 28, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 13, 2010 and incorporated herein by reference)
10.4+	Amendment to 1998 Stock Incentive Plan dated effective as of September 9, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on September 11, 2014 and incorporated herein by reference)
10.5+	Magellan Petroleum Corporation 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on January 17, 2013 and incorporated herein by reference)
10.6+	Form of Non-Qualified Stock Option Award Agreement between Magellan Petroleum Corporation and officers and directors (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on November 30, 2005 and incorporated herein by reference)
10.7+	Form of Amendment to Non-Qualified Stock Option Agreement between Magellan Petroleum Corporation and directors (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 15, 2008 and incorporated herein by reference)
10.8+	Non-Qualified Stock Option Award Agreement between Magellan Petroleum Corporation and William H. Hastings, dated as of February 3, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 9, 2009 and incorporated herein by reference)
10.9+	Non-Qualified Stock Option Performance Award Agreement between Magellan Petroleum Corporation and William H. Hastings, dated as of February 3, 2009 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on February 9, 2009 and incorporated herein by reference)
10.10+	Amended and Restated Warrant Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated March 11, 2010 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q filed on May 14, 2010 and incorporated herein by reference)
10.11+	Options and Stock Purchase Agreement dated October 10, 2014 between Magellan Petroleum Corporation and William H. Hastings (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on October 16, 2014 and incorporated herein by reference)
10.12+	Form of Indemnification Agreement for directors and officers (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on June 10, 2013 and incorporated herein by reference)
10.13+	Non-Qualified Stock Option Award Agreement between Magellan Petroleum Corporation and J. Thomas Wilson, dated July 9, 2009 (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on July 14, 2009 and incorporated herein by reference)
10.14+	Non-Qualified Stock Option Performance Award Agreement between Magellan Petroleum Corporation and J. Thomas Wilson, dated July 9, 2009 (filed as Exhibit 10.6 to the registrant's Current Report on Form 8-K filed on July 14, 2009 and incorporated herein by reference)

10.15+	Nonqualified Stock Option Award Agreement between Magellan Petroleum Corporation and J. Thomas Wilson dated November 16, 2011 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K/A filed on November 16, 2011 and incorporated herein by reference)
10.16+	Amended and Restated Employment Agreement between Magellan Petroleum Corporation and J. Thomas Wilson dated November 12, 2012 (filed as Exhibit 10.4 to the registrant’s Quarterly Report on Form 10-Q filed on February 11, 2013 and incorporated herein by reference)
10.17+	Amended and Restated Employment Agreement between Magellan Petroleum Corporation and J. Thomas Wilson effective December 11, 2013 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q filed on February 14, 2014 and incorporated herein by reference)
10.18+	Amended and Restated Employment Agreement effective as of October 31, 2014 between Magellan Petroleum Corporation and J. Thomas Wilson (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on December 5, 2014 and incorporated herein by reference)
10.19+	Amendment to Amended and Restated Employment Agreement executed on February 11, 2015 effective as of October 31, 2014 between Magellan Petroleum Corporation and J. Thomas Wilson (filed as Exhibit 10.9 to the registrant's Quarterly Report on Form 10-Q filed on February 12, 2015 and incorporated herein by reference)
10.20+	Form of Non-Qualified Stock Option Award Agreement between Magellan Petroleum Corporation and non-employee directors, dated April 1, 2010 (filed as Exhibit 10.2 to the registrant’s Quarterly Report on Form 10-Q filed on May 14, 2010 and incorporated herein by reference)

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10.21+	Employment Agreement between Magellan Petroleum Corporation and Antoine J. Lafargue, dated as of August 2, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on August 4, 2010 and incorporated herein by reference)
10.22+	Employment Agreement effective as of October 31, 2014 between Magellan Petroleum Corporation and Antoine J. Lafargue (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 5, 2014 and incorporated herein by reference)
10.23+*	Amendment to Employment Agreement effective as of October 12, 2015 between Magellan Petroleum Corporation and Antoine J. Lafargue
10.24+*	Restricted Stock Award Agreement effective as of October 12, 2015 between Magellan Petroleum Corporation and Antoine Lafargue
10.25+*	Transaction Incentive Agreement effective as of October 12, 2015 between Magellan Petroleum Corporation and Antoine J. Lafargue
10.26+*	Override Bonus Agreement effective as of October 12, 2015 between Magellan Petroleum Corporation and Antoine J. Lafargue
10.27+	Non-Qualified Stock Option Award Agreement between Magellan Petroleum Corporation and Antoine J. Lafargue, dated as of August 2, 2010 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on August 4, 2010 and incorporated herein by reference)
10.28+	Non-Qualified Stock Option Performance Award Agreement between Magellan Petroleum Corporation and Antoine J. Lafargue, dated as of August 2, 2010 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on August 4, 2010 and incorporated herein by reference)
10.29+	Nonqualified Stock Option Award Agreement between Magellan Petroleum Corporation and Antoine J. Lafargue dated November 30, 2011 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q filed on February 10, 2012 and incorporated herein by reference)
10.30+	Nonqualified Stock Option Performance Award Agreement between Magellan Petroleum Corporation and Antoine J. Lafargue dated November 30, 2011 (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q filed on February 10, 2012 and incorporated herein by reference)
10.31+	Form of Restricted Stock Award Agreement under the 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.75 to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2013 and incorporated herein by reference)
10.32+	Form of Nonqualified Stock Option Award Agreement under the 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.76 to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2013 and incorporated herein by reference)
10.33+	Form of Performance-Based Nonqualified Stock Option Award Agreement under the 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q filed on November 12, 2013 and incorporated herein by reference)
10.34+	Form of Restricted Stock Award Agreement under the 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on December 5, 2014 and incorporated herein by reference)
10.35+	Form of Nonqualified Stock Option Performance Award Agreement for Performance Goal Options under the 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q filed on February 12, 2015 and incorporated herein by reference) (portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the U.S. Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934)
10.36+	Form of Nonqualified Stock Option Performance Award Agreement for Target Stock Price Options and Performance Goal Options under the 2012 Omnibus Incentive Compensation Plan (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q filed on February 12, 2015 and incorporated herein by reference) (portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the U.S. Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities

	Exchange Act of 1934)
10.37+	Employment Agreement effective as of October 31, 2014 between Magellan Petroleum Corporation and Matthew R. Ciardiello (filed as Exhibit 10.3 to the registrant’s Current Report on Form 8-K filed on December 5, 2014 and incorporated herein by reference)
10.38	Registration Rights Agreement among Magellan Petroleum Corporation and the members of Nautilus Technical Group LLC and Eastern Rider LLC, dated September 2, 2011 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q filed on November 14, 2011 and incorporated herein by reference)
10.39	Gas Supply and Purchase Agreement among Magellan Petroleum (N.T.) Pty. Ltd., Santos Limited, and Santos QNT Pty. Ltd., dated September 14, 2011 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q filed on November 14, 2011 and incorporated herein by reference)
10.40+	Collateral Purchase Agreement dated January 14, 2013 between Sopak AG and Magellan Petroleum Corporation (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 17, 2013 and incorporated herein by reference)
10.41+	Series A Convertible Preferred Stock Purchase Agreement dated May 10, 2013 between Magellan Petroleum Corporation and One Stone Holdings II LP (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 13, 2013 and incorporated herein by reference)
10.42*	First Amendment dated as of August 3, 2015 to Series A Convertible Preferred Stock Purchase Agreement dated May 10, 2013 between Magellan Petroleum Corporation and One Stone Holdings II LP

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10.43+	Gas Supply and Purchase Agreement dated September 12, 2013, between Magellan Petroleum (NT) Pty Ltd and Power and Water Corporation (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on September 12, 2013 and incorporated herein by reference) (portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the U.S. Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934)
10.44	Loan Agreement dated September 17, 2014 between Nautilus Poplar LLC as the Borrower, Magellan Petroleum Corporation as the Guarantor and West Texas State Bank as the Lender (filed as Exhibit 10.57 to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2014 and incorporated herein by reference)
10.45	Promissory Note Agreement dated September 17, 2014 between Nautilus Poplar LLC as the Borrower and West Texas State Bank as the Lender (filed as Exhibit 10.58 to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2014 and incorporated herein by reference)
10.46	Guarantee Agreement dated September 17, 2014 between Nautilus Poplar LLC as the Borrower, Magellan Petroleum Corporation as the Guarantor and West Texas State Bank as the Lender (filed as Exhibit 10.59 to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2014 and incorporated herein by reference)
10.47	Deed of Trust, Mortgage, Security Agreement, Assignment of Production and Financing Statement dated September 17, 2014 between Nautilus Poplar LLC as the Grantor and West Texas State Bank as Lender (filed as Exhibit 10.60 to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2014 and incorporated herein by reference)
10.48*	Restated Loan Agreement dated June 30, 2015, among Nautilus Poplar LLC as the Borrower, Magellan Petroleum Corporation as the Guarantor, and West Texas State Bank as the Lender
10.49*	Amended and Restated Unlimited Guaranty dated June 30, 2015, among Nautilus Poplar LLC as the Borrower, Magellan Petroleum Corporation as the Guarantor, and West Texas State Bank as the Lender
10.50*	First Amendment dated June 30, 2015 to Deed of Trust dated September 17, 2014 among Nautilus Poplar LLC as the Borrower, Magellan Petroleum Corporation as the Guarantor, and West Texas State Bank as the Lender
10.51*	Amended and Restated Promissory Note dated June 30, 2015, among Nautilus Poplar LLC as the Borrower, Magellan Petroleum Corporation as the Guarantor, and West Texas State Bank as the Lender
10.52	Controlled Equity Offering[SM] Sales Agreement, dated as of December 24, 2014, between Magellan Petroleum Corporation and Cantor Fitzgerald & Co. (filed as Exhibit 1.1 to the registrant's Current Report on Form 8-K filed on December 24, 2014 and incorporated herein by reference)
21.1*	Subsidiaries of the Registrant
23.1*	Consent of EKS&H LLLP
23.2*	Consent of Allen & Crouch Petroleum Engineers Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Summary reserves report of Allen & Crouch Petroleum Engineers, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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

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SIGNATURES

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

MAGELLAN PETROLEUM CORPORATION
(Registrant)

Date: October 13, 2015	By:	/s/ J. Thomas Wilson John Thomas Wilson, President and Chief Executive Officer (as Principal Executive Officer)
Date: October 13, 2015	By:	/s/ Antoine J. Lafargue Antoine J. Lafargue, Senior Vice President - Chief Financial Officer, Treasurer and Corporate Secretary (as Principal Financial and Accounting Officer)

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

/s/ J. Thomas Wilson John Thomas Wilson, President and Chief Executive Officer (as Principal Executive Officer), and Director	Date:	October 13, 2015
/s/ Antoine J. Lafargue Antoine J. Lafargue, Senior Vice President - Chief Financial Officer, Treasurer and Corporate Secretary (as Principal Financial and Accounting Officer)	Date:	October 13, 2015
/s/ Vadim Gluzman Vadim Gluzman, Director	Date:	October 13, 2015
/s/ Robert I. Israel Robert I. Israel, Director	Date:	October 13, 2015
/s/ Brendan S. MacMillan Brendan S. MacMillan, Director	Date:	October 13, 2015
/s/ Ronald P. Pettirossi Ronald P. Pettirossi, Director	Date:	October 13, 2015
/s/ J. Robinson West J. Robinson West, Director	Date:	October 13, 2015

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INDEX TO EXHIBITS

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