MAGELLAN PETROLEUM CORP /DE/
Form 10-K
September 18, 2014

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, 2014,
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
for the transition period from __________ to __________
Commission file number 001-5507
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. þ
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.:

Large accelerated filer 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 $1.030 closing price per share of the registrant's common stock as reported by the NASDAQ Capital Market, as of December 31, 2013 (the last business day of the most recently completed second fiscal quarter) was $42,236,074. 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.

As of September 8, 2014, the registrant had 45,586,778 shares of common stock outstanding, which is net of 9,425,114 treasury shares held by the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the 2014 annual meeting of stockholders to be filed within 120 days after June 30, 2014, 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

GENERAL

Magellan Petroleum Corporation (the "Company" or "Magellan" or "we") is an independent oil and gas exploration and production company focused on the development of a CO_2-enhanced oil recovery ("CO_2-EOR") program at Poplar Dome in eastern Montana and the exploration of unconventional hydrocarbon resources in the Weald Basin, onshore UK. Magellan also owns an exploration block, NT/P82, in the Bonaparte Basin, offshore Northern Territory, Australia, which the Company currently plans to farmout; and an 11% 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").

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.

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 investing in these projects to establish their technical and economic viability. In turn, we are focused on determining the most efficient way to create the greatest value and highest returns for our shareholders.

SIGNIFICANT DEVELOPMENTS IN FISCAL YEAR 2014

During fiscal year 2014, the Company achieved a number of key milestones in the strategy of creating value from our existing assets.

Progress on Key Projects

Portfolio rationalization and funding of core projects. On March 31, 2014 (the "Central Closing Date"), pursuant to the Share Sale and Purchase Deed (the "Sale Deed") dated February 17, 2014 (the "Execution Date"), 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, to Central's wholly owned subsidiary Central Petroleum PV Pty. Ltd ("Central PV"). In exchange for the assets, Central paid to Magellan cash in the total amount of AUD $20.0 million, paid in two installments of AUD $15.0 million and AUD $5.0 million on March 31, 2014, and April 15, 2014, respectively, and 39.5 million newly issued shares of Central stock, worth AUD $15.0 million as determined on the Execution Date, equivalent to an approximate 11% ownership interest in Central as of the Central Closing Date. Magellan is currently Central's single largest shareholder. Based on the Central closing price on September 5, 2014, these shares of stock represent a total value of AUD $12.2 million, or an AUD $2.8 million decrease over the issuance value on the Execution Date. In addition, Magellan is entitled to receive bonus payments from Central in the event that future gas sales revenues from Palm Valley exceed certain levels. The Company also maintained its right to the Mereenie Bonus, which it received as part of the asset swap agreement with Santos QNT Pty Ltd ("Santos") in September 2011, which entitles the Company to potential total cash payments ranging from AUD $5.0 million to AUD $17.0 million based on certain gas sales thresholds at Mereenie.

This transaction represents a major step in the rationalization of the Company's non-core assets. Furthermore, the

Company expects that the consideration from the transaction combined with the Company's previous cash balances provide the Company with sufficient funds to complete the CO_2-EOR pilot project at Poplar, to participate in the drilling of its first exploratory wells in the UK, and to finance its ongoing operations. By selling Dingo, the Company avoided the need to finance an AUD $20.0 million development, including necessary gas transportation facilities, which would have rendered the

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Australian operations cash flow negative over the next five years. The Company has also been able to close its Brisbane, Australia, office, which is expected to reduce consolidated general and administrative expenses by approximately $2.0 million to $3.0 million per year and bring the Company closer to operating cash flow break-even levels. In addition, the 11% ownership stake in Central should allow the Company to maintain broader exposure to the Amadeus Basin through a player who controls most of the basin's acreage through farmouts to significant operators and represents an attractive investment opportunity with significant value appreciation potential.

For a summary of the key terms of the Sale Deed and further information on the Amadeus Basin Sale, please see the Company's Current Reports on Form 8-K filed with the SEC on February 18, 2014, and March 31, 2014.

Poplar CO_2-EOR pilot project. Fiscal year 2014 was a pivotal year for CO_2-EOR development at Poplar, during which period the Company finalized plans for, drilled five wells and installed the facilities for, and then began, the pilot program. In July 2013, the Company signed an approximate two-year CO_2 supply contract with Air Liquide for the purchase of CO_2 volumes necessary to complete the CO_2-EOR pilot project. In August 2013, the Company obtained permits from the US Bureau of Land Management to drill the five wells necessary for the pilot project. Between September and December 2013, the Company drilled all five pilot wells to total depth of approximately 5,800 feet. From January to March 2014, the Company completed and tested the wells and installed necessary surface facilities and CO_2 injection equipment. During this period, the Company collected various cores and logs, which contributed to a more refined 3-D reservoir model of the Charles formation at Poplar and will in turn improve our analysis of the performance of the CO_2-EOR pilot. At the end of March 2014, the Company began injecting CO_2 through the injection well, marking the beginning of the injection phase of the pilot. Between March and April 2014, the Company monitored and conducted preliminary tests of the effectiveness of CO_2 injection into the Charles formation. Between May and August 2014, the Company paused CO_2 injection in order to (i) resolve issues that were identified with the cementing of the wells, (ii) amend and simplify the completion equipment design of the wells to address certain technical issues with packers and improve the overall reliability of the completion equipment, and (iii) perform water shut-off treatments on all of the pilot wells. Water shut-off treatments conducted in the pilot wells are identical to the treatments generally performed in other wells at Poplar and require approximately one month to complete. Their purpose is to enhance the amount of CO_2 injected in the reservoir matrix through the injection well and to block water production from fractures in the producer wells and enhance the amount of oil produced from the reservoir. In late August 2014, the Company began CO_2 injection once again.

Based on the work completed to date, the Company has not identified any technical issues that would jeopardize the viability of CO_2-EOR at Poplar. Although results to date are very preliminary, the Company has already acquired critical data points that indicate that CO_2-EOR at Poplar could be technically viable. Initial CO_2 injection resulted in the relatively quick increase in down-hole pressures in the injector well bore to levels necessary, as determined by Core Labs in 2012, for the miscibility of CO_2 and oil at Poplar. This pressuring up indicated that CO_2 injection did not encounter a breakthrough, commonly called a "thief zone", through which CO_2 can by-pass the reservoir and thereby reduce the efficacy of the CO_2 in sweeping oil from the reservoir. Moreover, achieving miscibility pressure is essential for CO_2-EOR to be effective, and the ability to reach miscibility pressures relatively quickly implies that CO_2-EOR could be economically feasible at Poplar.

The Company has not yet opened the production wells. Once open, the primary production from these wells will provide a baseline against which we can measure the impact on production of CO_2 injection.

UK - Central Weald Licenses. During fiscal year 2014, the Company obtained a key extension to its central Weald Petroleum Exploration and Development Licenses ("PEDLs") (PEDLs 231, 234, and 243), which it co-owns equally with Celtique Energie Holdings Ltd ("Celtique"). This extension should allow the Company sufficient time to establish the unconventional prospects in these licenses. Also during the period, Magellan and Celtique advanced plans to drill a first exploratory well on a conventional prospect at Broadford Bridge, which is located within the license area of PEDL 234, by the end of the second quarter of fiscal year 2015 subject to the finalization of the permitting process and rig availability.

In May 2014, the British Geological Survey ("BGS"), in association with the UK Department of Energy and Climate Change ("DECC"), publicly released a report (the "BGS Report") on the Jurassic shale formations in the Weald Basin. Maps presented in the BGS Report illustrate that the three licenses co-owned by Magellan cover most of the area prospective for unconventional development in the Weald Basin. In addition, tight conventional formations present between the thick shale packages of the Jurassic and Cretaceous sections may be prospective for development. These formations were previously tested with encouraging results by Cuadrilla at the Balcombe-1 well, which offsets Magellan's central Weald licenses to the east.

UK - Peripheral Weald Licenses. During fiscal year 2014, the Company executed a farmout of PEDLs 137 and 246, which contain the Horse Hill prospect, to Angus Energy ("Angus"), a privately owned UK based exploration and development Company. Pursuant to the terms of the farmout, Angus is obligated to fund 100% of the cost of drilling a vertical exploratory well in order to earn a 65% working interest in, and operatorship of, the license. The Horse Hill prospect was identified on 2-D seismic data reprocessed by the Company. The conventional hydrocarbon prospect, which is Triassic in age, is approximately 10,000 feet deep and is expected to primarily contain gas. Angus spud the Horse Hill-1 exploratory well in August 2014, and,

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as of the date hereof, the drilling of this well is ongoing. During the drilling of the Horse Hill-1 well, logs and cores are planned to be collected from the Kimmeridge and Liassic formations, which constitute the main potential unconventional formations in the Weald Basin and will contribute to the Company's overall understanding of the potential for unconventional development in the Weald Basin.

During the fiscal year, the Company also rationalized the portfolio of other licenses in which it owns interests on the periphery of the Weald Basin. Effective from March 2014, the Company, together with its partners in the respective licenses, relinquished PEDLs 155 and 256 due to a determination of limited development prospectivity within the license areas, and PEDL 240, which was located on the Isle of Wight, due to inability to secure a suitable drill site. In June 2014, PEDL 232, co-owned equally by Magellan and Celtique, was relinquished several weeks prior to its expiration date of June 30, 2014. The Company did not believe these licenses contained material hydrocarbon resources and did not consider them core to its UK strategy. The Company does not face abandonment or restoration liabilities with respect to these licenses.

With respect to PEDL 126, which contains the Markwells Wood-1 well, during fiscal year 2014 the Company and its partners contracted Schlumberger to undertake a study of the unconventional resource potential of the license area. This study indicated that the area is probably immature for oil or gas generation and therefore unlikely to have unconventional shale oil or gas potential. This finding was consistent with the Company's understanding of the geology of the Basin.

Following the study, the joint venture reached an agreement with DECC to relinquish all of the license area except for 11.2 square kilometers (2,768 acres) around and including the Markwells Wood-1 well bore in exchange for an extension of the exploration term by one year to June 30, 2015. During fiscal year 2015, the Company and its partners plan to evaluate the sale or farmout of the remaining license area to a third party on the basis of the relatively small conventional reservoir contained therein and the potential value of the wellbore to a third party. If the Company and its partners are unable to sell or farmout PEDL 126, the Company may face a plugging and abandonment liability of approximately $394 thousand net to its interest.

Australia - NT/P82. During fiscal year 2014, the Company completed the processing and interpretation of the 2-D and 3-D seismic surveys that the Company shot over part of NT/P82 in the Bonaparte Basin in December 2012. The Company believes that these seismic studies confirm the presence within the block of two large prospects. In April 2014, the Company received from the Australian government a one-year extension of the deadline for the drilling of an exploration well in NT/P82 until May 2016. This extension will allow the Company greater flexibility in identifying partner(s) for, and executing a farmout of, this exploration block. On the basis of both developments, in the fourth quarter of fiscal year 2014, the Company began a farm-out process to identify a suitable partner experienced in offshore drilling to drill and carry Magellan for at least one exploratory well in the license area in exchange for operatorship of, and an interest in, the license. If the drilling operations are successful, the Company will likely seek to sell its remaining interest in the license and redeploy the proceeds in its core activities.

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 2013 and 2014 exclude the impact of these assets on such amounts.

Revenues. Revenues for the year ended June 30, 2014, totaled $7.6 million, compared to $6.1 million in the prior year, an increase of 24%. The $1.5 million increase in revenue over the prior year was primarily due to both an increase in production volumes ($1.2 million) resulting from the favorable impact of workovers and water shut-off treatments on several wells during the year, and an increase in WTI benchmark pricing ($0.7 million), which increases were partially offset by a decrease in the pricing differential realized at Poplar ($0.4 million).

Net Income and Earnings per Share. Net income totaled $13.8 million ($0.30/basic share), compared to a net loss of $20.5 million ($(0.41)/basic share) in the prior year. The increase in net income was primarily the result of a gain on sale of assets of $30.0 million recognized as a result of the sale of the Amadeus Basin assets in March 2014.

Adjusted EBITDAX. Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) was negative $5.6 million, compared to negative $7.5 million in the prior year, a change of 26%. The improvement in Adjusted EBITDAX resulted from an increase in revenues of $1.5 million and a reduction in general and administrative expense (excluding stock based compensation and foreign transaction loss) of $1.9 million, partially offset by an increase in lease operating expense of $1.4 million.

Cash. As of June 30, 2014, Magellan had $16.4 million in cash and cash equivalents, compared to $32.5 million at the end of the prior fiscal year. The decrease of $16.0 million was the result of net cash used in operating activities of $11.7 million, net cash used in investing activities of $2.4 million, net cash used in financing activities of $0.7 million, and net cash used in discontinued operations of $1.4 million, partially offset by a $0.1 million increase in cash from the effect of exchange

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rates. The $2.4 million of net cash used in investing activities was the result of $20.9 million of capital expenditures primarily relating to the CO_2-EOR pilot at Poplar, partially offset by $18.6 million in proceeds from the sale of the Company's Amadeus Basin assets.

Securities available-for-sale. As of June 30, 2014, Magellan had $11.9 million in securities available for sale, consisting primarily of the Company's investment in the 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 2015

During fiscal year 2015, Magellan intends to continue executing on its strategy of proving the potential of its existing assets. The Company will be particularly focused on the following projects:

- progressing the CO_2-EOR pilot project at Poplar to such a point that the Company will be able to assess the technical and economic viability of a full CO_2-EOR program at the field;
- drilling one and possibly two wells in the UK to evaluate the potential of the various conventional and unconventional formations in our licenses there; and
- executing a farmout of NT/P82 to a partner qualified in offshore drilling that will result in the drilling of at least one test well over the license area by May 2016.

The Company believes that each of these projects has significant potential that, if realized, could materially impact the Company's reserves and the underlying net asset value per share and eventually allow the Company to generate positive cash flow from operations and raise financing on attractive terms. Specific steps and milestones for each of these key areas are discussed below. By pursuing these courses of action in parallel, the Company expects that, over the next 12 months, it will be able to validate the value potential of these assets and will be able to determine the most appropriate course of action with respect to each asset to achieve the best value for its shareholders.

CO_2-EOR Pilot Project

During fiscal year 2015, the Company will continue to conduct the CO_2-EOR pilot at Poplar with the objective of obtaining meaningful preliminary results in the third quarter of fiscal year 2015. Following implementation of improvements in well completion design and surface facility injection systems and the re-initiation of CO_2 injection during the summer of 2014, CO_2 injection is expected to be continuous over the coming months. The Company will also soon open for production the four pilot producer wells. Once open, the primary production from these wells will provide a baseline against which we can measure the impact on production of CO_2 injection. Over the upcoming months, the Company will be continuously monitoring key data in real-time, including CO_2 injection pressures, volumes, and rates, and production from the producer wells. The Company will then integrate this data into its 3-D reservoir model to enhance its interpretation of the reservoir and its understanding of the efficacy of CO_2-EOR at Poplar.

With these results, and with additional data from the pilot to be received over the remainder of the fiscal year, the Company anticipates that it will be able to quantify with greater certainty both the incremental volume of oil that could be recoverable from Poplar through the use of CO_2-EOR techniques and the corresponding increase in the quantity of reserves the Company can record with respect to CO_2-EOR.

UK - Central Weald Licenses

In fiscal year 2015, the Company will work with its partner, Celtique, to spud the Broadford Bridge-1 well, the first exploratory well in the central Weald licenses. The Broadford Bridge-1 well is designed and permitted to test a conventional prospect in a Triassic-age formation, similar to the prospect targeted at Horse Hill. The Company and its partner Celtique also intend to collect logs and cores from the Kimmeridge and Liaissic formations, which hold potential for unconventional development. According to an agreement with DECC, this well, which is located within the license area of PEDL 234, will satisfy the drilling obligations for both PEDLs 234 and 243. Currently, the process of obtaining relevant regulatory and planning permissions is substantially complete, and the timing of spudding this well will depend primarily on rig availability. Currently, the Company expects the well to be spud late in the second or early in the third quarter of fiscal year 2015.

In parallel, the Company will continue efforts with Celtique to permit additional drilling locations within the Central Weald licenses. The Company expects that it can permit well sites successfully such that it can meet its drilling obligations for

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these licenses within the required time frame of before June 30, 2016. Although the UK regulatory and permitting process can be challenging, particularly with respect to locally granted permits, the UK government has made significant efforts to improve the efficiency of such processes with various proposed changes to incentive schemes, regulatory processes, and laws relevant to onshore unconventional oil and gas development. The Company expects that such proposed changes will become effective during fiscal year 2015.
During fiscal year 2015, there are a number of wells scheduled to be drilled onshore in the UK by other industry players, some of which will be hydraulically fractured. As these various new wells are permitted and drilled, the Company expects that the permitting and regulatory processes will become smoother and more efficient.

UK - Peripheral Weald Licenses
On September 3, 2014, Angus commenced drilling operations on the Horse Hill-1 well. The well is expected to be drilled to a depth of approximately 8,700 feet and to test a number of Jurassic-aged conventional stacked oil formations, including the Portland Sandstone, Corallian Sandstone, and Great Oolite formations, and a Triassic-aged conventional gas target. The well will be drilled vertically and will not be hydraulically fractured. The Horse Hill-1 well lies within the license area of PEDL 137. Pursuant to a farmout agreement executed in December 2013, Horse Hill Development Limited, a majority-owned subsidiary of Angus Energy, will carry Magellan for its share of the costs of this well in exchange for having received operatorship of, and a 65% interest in, both the well and the license. During drilling, Magellan will have the opportunity to core and log at its own expense several shale and tight formations in the Cretaceous and Jurassic sections, including the Kimmeridge Clay and Liassic formations. The Company expects that the information gained through these activities will provide valuable insights into the technical and economic viability of unconventional development elsewhere in the Weald Basin.
With respect to the Company's interests in its two other licenses on the periphery of the Weald Basin, P1916 and PEDL 126, the Company currently has no plans to pursue exploration or drilling activities. The Company does not believe that a suitable drilling location can be permitted for P1916. As such, the Company is considering, together with its joint venture partners, the relinquishment of this license. During fiscal year 2015, the Company and its partners in PEDL 126 will evaluate the sale or farmout of the remaining license area to a third party on the basis of the relatively small conventional reservoir contained therein.
During fiscal year 2015, the UK government will hold the 14th Annual Landward Licensing Round, through which companies will be able to apply for various oil and gas exploration permits onshore in the UK. Magellan does not intend to participate in this round, since we believe that our central Weald licenses cover substantially all of the Weald Basin's acreage prospective for unconventional development, and we have not identified attractive conventional targets in other areas.

NT/P82, Offshore Australia
Based on the results of 2-D and 3-D seismic interpretation completed in fiscal year 2014, the Company began a process in the fourth quarter of fiscal year 2014 to identify a farmout partner experienced in offshore drilling. In completing a 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 drill exploration wells by May 2016 over the large gas prospects identified in the block. 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 2015.

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 11% ownership interest in Central. 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 to the consolidated financial statements included in Item 8: Financial Statements and Supplementary Data of this report.

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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 net acres, and the working interests in various oil and gas leases that are adjacent to or near EPU ("Northwest Poplar" or "NWP") totaling approximately 4,000 net 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. As a secondary priority at Poplar, the Company plans to continue evaluating the effectiveness of water shut-off treatments on conventional

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production in these formations. At a later date, 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. In the fourth quarter of fiscal year 2014, the Company executed a water shut-off treatment on one of these three wells, the EPU 120, in an attempt to stimulate production. The results of this treatment are still under evaluation. In addition to this treatment, 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 seven 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 Energie operates these licenses. On the periphery of the Weald Basin, Magellan maintains non-operated interests in four additional exploration licenses, representing an additional 16 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 farmout process to identify a suitable partner to drill at least one exploratory well. Under the terms of the permit, the Company, or its farmout partner, is required to drill one exploratory well by May 2016 or the permit will expire.
Central. Magellan is the owner of approximately 39.5 million shares of stock in Central, representing an approximate 11% ownership interest as of September 5, 2014. 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, and other factors. The below table presents a summary of our proved and probable reserves as of June 30, 2014.

	Oil (Mbbls)	
United States Reserves:		
Proved developed producing ("PDP")	1,417	
Proved developed not producing ("PDNP")	1,078	
Proved undeveloped ("PUD")	3,241	
Total reserves	5,736	
PDP%	25	%
PDNP%	19	%
PUD%	56	%
Probable undeveloped reserves	1,950	
Total proved and probable reserves	7,686	
Proved %	75	%
Probable %	25	%

Proved Undeveloped Reserves

As of June 30, 2014, we had 3,241 Mbbls of proved undeveloped reserves, representing a decrease of 2,546 Mbbls, or 44%, over the prior year figure. The below table presents a summary of our PUDs for the year ended June 30, 2014:

	Total (Mbbls)	
Fiscal year opening balance	5,787	
Removed due to change in drilling schedule	(5,787	)
Added from drilling program	3,241	
Fiscal year ended June 30, 2014	3,241	

During the fiscal year, we did not convert any proved undeveloped reserves to proved developed reserves. The proved undeveloped reserves as of June 30, 2013, which were related to the planned drilling of 16 wells, were originally identified and recorded in fiscal year 2010 in relation to a 20-well infill drilling program at Poplar. However, in light of the Company's increasing focus on CO_2-EOR and the fact that no wells for this drilling program have been drilled to date, the Company decided to change its plans such that those locations are currently not scheduled to be drilled within five years from the date of original booking, and to remove all of the related proved undeveloped reserves from its books as of June 30, 2014. During the fiscal year ended June 30, 2014, the Company added new proved undeveloped reserves amounting to 3,241 Mbbls and attributable to a new 9-well drilling program at Poplar. The nine well locations in this program are at Poplar in the immediate vicinity of the five wells that have been recently drilled for the CO_2-EOR pilot project. The Company plans to drill these wells as infill drilling locations for primary production from the Charles formation, with the additional benefit of potentially being converted for the purpose of CO_2-EOR development given their location as offsets to the pilot producer wells. In parallel with the results of the Company's CO_2-EOR pilot project, these new nine locations at Poplar are scheduled to be drilled within the next five years.

As of June 30, 2014, 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.

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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 more likely than 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, 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 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 lower percentage recovery of the hydrocarbons in place than assumed for proved 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 year ended June 30, 2014, and by the Company's now former Operations Manager, Blaine Spies, for the fiscal year ended June 30, 2013. 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. Mr. Spies has over 20 years of operation and technical engineering experience in the oil and gas industry. Prior to his appointment with Magellan, Mr. Spies was the Operations Manager at American Oil & Gas, responsible for drilling and completion operations in North Dakota. Mr. Spies also has experience in the Rocky Mountain and Gulf Coast regions. He received his Bachelors of Science in Petroleum Engineering from the Colorado School of Mines and his Masters in Business Administration from the Colorado Technical University. 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) to the consolidated financial statements in this Form 10-K.

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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, 2014	2013
United States:		
Volumes (Mbbls)	88	72
Average realized prices ($/boe) [1]	$86.38	$84.91
Lease operating ($/boe)	$71.10	$67.17

[1] Prices per bbl is reported net of royalties.

Total production increased from 72 Mbbls in fiscal year 2013, to 88 Mbbls in fiscal year 2014. The increase was primarily the result of increased production from water shut-off treatments and workovers. The average realized price increased to $86.38/boe from $84.91/boe in the prior year. The increase was primarily the result of decreasing differentials relative to the benchmark pricing (WTI) realized at the Poplar field. The Company does not currently engage in any oil and gas hedging activities. Lease operating expenses increased to $71.10/boe from $67.17/boe in the prior year. The increase is related to workover activity, maintenance on wells, and lease road maintenance.

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 US at Poplar as of June 30, 2014.

	Productive Wells
United States:	
Gross oil wells [1]	34.0
Net oil wells [2]	32.6

[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, 2014		2013	
	Productive [2]	Dry [3]	Productive [2]	Dry [3]
United States:				
Development wells, net [1]	5.0	—	4.0	1.0
Exploratory wells, net [1]	—	—	1.0	—
Total net wells	5.0	—	5.0	1.0

[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 September 18, 2014, of our wells that were still in progress as of June 30, 2014.

	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, 2014.

	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	32	296,515	139,523	296,595	139,555
Australia (NT/P82)	—	—	1,566,647	1,566,647	1,566,647	1,566,647
Total	22,993	22,701	1,863,162	1,706,170	1,886,155	1,728,871

[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 34 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 DECC, and PEDLs and Seaward Production Licenses (denoted by a "P") issued by DECC are subject to the Petroleum Act. A licensee has the exclusive right to produce, explore, and develop petroleum from the land subject to the payment of rental to 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 DECC. If a development program is approved by 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 expiration, 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.

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The below table summarizes the permits we maintain in the UK as of June 30, 2014.

License	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres (1)	Net acres (2)
Central Weald licenses prospective for unconventional development:						
PEDL 231	Weald	6/30/2016	Celtique	50%	98,800	49,400
PEDL 234	Weald	6/30/2016	Celtique	50%	74,100	37,050
PEDL 243	Weald	6/30/2016	Celtique	50%	74,100	37,050
Subtotal					247,000	123,500
Licenses containing Horse Hill conventional Triassic play:						
PEDL 137 (3)	Weald	9/30/2014	Angus	35%	24,525	8,584
PEDL 246 (3)	Weald	6/30/2015	Angus	35%	10,769	3,769
Subtotal					35,294	12,353
Other licenses on periphery of Weald Basin:						
PEDL 126	Weald	6/30/2015	Northern	40%	2,766	1,107
P1916	Wessex	1/31/2016	Northern	23%	11,535	2,595
Subtotal					14,301	3,702
Total					296,595	139,555

(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) Formal transfer of 65% ownership in, and operatorship of, PEDLs 137 and 246 is subject to Angus funding and drilling a first obligation well.

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 below table summarizes the permit we maintain in Australia as of June 30, 2014.

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 consolidated oil production revenue is derived from its NP segment and was generated from a single customer, Plains Marketing, LP, for the years ended June 30, 2014, and 2013, respectively.

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 strength 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 the strength of our balance sheet 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, 2014, the Company had a total of 26 full-time employees. 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.

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, 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

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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.

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 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;

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- 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.

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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.

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. 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

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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.

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.

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 income (loss) attributable to Magellan, 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) net interest expense (income), (vii) fair value revision of contingent consideration payable, (viii) other income, and (ix) net (income) loss 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 income (loss) 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,	
	2014	2013
	(In thousands)	
Net income (loss) attributable to Magellan Petroleum Corporation	$15,509	$(19,767)
Depletion, depreciation, amortization, and accretion expense	1,123	1,121
Exploration expense	3,484	7,907
Stock based compensation expense	2,009	848
Foreign transaction loss	165	18
Impairment expense	—	890
Net interest expense (income)	243	(298)
Fair value revision of contingent consideration payable	(2,403)	(458)
Other income	(146)	(698)
Net (income) loss from discontinued operations	(25,551)	2,938
Adjusted EBITDAX	$(5,567)	$(7,499)

For clarification purposes, the below 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,	
	2014	2013
	(In thousands)	
Total revenues	$7,601	$6,131
Less:		
Lease operating	(6,257)	(4,851)
General and administrative	(9,085)	(9,645)
Plus:		
Stock based compensation expense	2,009	848
Foreign transaction loss	165	18
Adjusted EBITDAX	$(5,567)	$(7,499)

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

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 commenced the CO_2 injection phase of the program. Through June 30, 2014, we had incurred approximately $19.1 million in capitalized costs in connection with the pilot program, and we currently estimate that additional costs of the program, including capital and certain operating expenditures, will be approximately $6.9

million. While laboratory analysis and other preliminary tests indicate that a CO_2-EOR project at Poplar could be technically and economically viable on a full-field basis, the additional

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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 productive wells. If the results of the pilot program do not support the continued use of CO_2-EOR methods at Poplar or if CO_2-EOR methods 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 our ability to obtain sufficient quantities of CO_2. Although we currently have a two-year CO_2 supply agreement for the pilot program, if we become limited in the quantities of CO_2 available to us, we may not have 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 disproportionally 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 Energie 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 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.

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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 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, in April 2014 we commenced a farmout process for our NT/P82 exploration permit area, in which we expect 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 exploration budget 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 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 represent 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, 2014, the Central shares were carried on our balance sheet at a fair value of AUD $12.6 million, based on the closing per share market price for Central stock as reported on the ASX on that date.
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 from our investment in Central than we expect.

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-

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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.

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.

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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.

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.

We have limited management and staff and are dependent upon partnering arrangements.
We had 26 total employees as of June 30, 2014. 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
- 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.

Oil and natural gas prices are volatile. A decline 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;

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- 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. 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 gas sales not governed by existing contracts would generate lower revenue if natural gas prices were 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 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

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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 National Enforcement Initiatives for 2014 to 2016 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." 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. 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.

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

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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 additional 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 may limit our ability to book additional proved undeveloped reserves as we pursue drilling programs on our undeveloped properties. In addition, we may be required to write down our proved undeveloped reserves if we do not drill the scheduled wells within the required five-year timeframe.

Substantial capital is required for our business.

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 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 were limited, we would 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.

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 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.

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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 discounted future net cash flows of that depletion pool. A significant decline in oil or natural gas prices from current levels, or other factors, could cause a future 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.

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

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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. In addition, the strengthening of the US dollar against the Australian dollar in recent periods has had a negative impact on our prior revenues generated in the Australian dollar, as well as our operating income and net income on a consolidated basis. Our foreign exchange gain for the fiscal year ended June 30, 2014, was $165 thousand and is included under general and administrative expenses in the consolidated statements 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 Fiscal Year 2015 Budget Proposal includes 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 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 20.1 million shares of Series A preferred stock as of June 30, 2014, which represents approximately 31% of our outstanding commons 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 1988. In order to retain the interests granted by the licenses, we are required to meet

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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, 2014, we had 10,492,291 stock options outstanding, of which 7,285,622 were fully vested and exercisable, and 20,089,436 shares of Series A convertible preferred stock outstanding. In addition, on July 1, 2014, we granted a total of 96,330 shares of common stock to non-employee directors under our 2012 Omnibus Incentive Compensation Plan, as annual equity awards pursuant to our compensation policy for non-employee directors. As of that date, there were 172,447 shares of common stock remaining available for future awards under that plan. If all of the 10,492,291 outstanding stock options, which have exercise prices ranging from \$0.79 to \$2.41 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 19% and 31%, 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.

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 October-November 2012, 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 January 2013. On September 8, 2014, the closing market price of our common stock was \$1.93 per share, but the closing market price of our common stock was as low as \$1.02 on certain trading days in 2014 and below \$1.00 on certain trading days in 2013. 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.

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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% 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.

One Stone Holdings II LP owns 20,089,436 shares of our Series A convertible preferred stock, and thereby currently beneficially owns approximately 31% 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 seven-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 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 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 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.

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ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

ITEM 3: LEGAL PROCEEDINGS

We may be involved from time to time in legal proceedings relating to disputes or claims arising out of our operations in the normal course of business. As of the filing date of this report, there are no pending legal proceedings that we believe could have a material adverse effect on our financial condition, results of operations, or cash flows.

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.

Quarter ended	High	Low
June 30, 2014	$2.52	$1.40
March 31, 2014	$1.54	$1.02
December 31, 2013	$1.13	$1.01
September 30, 2013	$1.14	$0.99
June 30, 2013	$1.19	$0.97
March 31, 2013	$1.33	$0.86
December 31, 2012	$1.06	$0.74
September 30, 2012	$1.63	$0.91

HOLDERS

As of September 8, 2014, the number of record holders of Magellan's common stock was 4,400 and, based upon inquiry, the number of beneficial owners was approximately 6,100.

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.

ISSUER PURCHASES OF EQUITY SECURITIES

The below table provides information about purchases of the Company's common stock by the Company during the periods indicated.

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 to the consolidated financial statements included in this Form 10-K.

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced program	Maximum value of shares that may yet be purchased under the program
April 1, 2014 - April 30, 2014	—	$—	—	$1,863,022
May 1, 2014 - May 31, 2014	—	$—	—	$1,863,022
June 1, 2014 - June 30, 2014	—	$—	—	$1,863,022
Total	—	$—	—	$1,863,022

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 of $2.0 million in shares of its common stock. This authorization superseded the prior plan announced on December 8, 2000, and expired on August 21, 2014. During Fiscal year 2013, the Company repurchased 149,539 shares of its common stock under the stock repurchase program between November 2012 and February 2013, and 9,264,637 shares of its common stock through a Collateral Agreement (see Note 11 to the consolidated financial statements included in this Form 10-K). During this period, the Company's share price was below $1.00 per share. No further repurchases of the Company's common stock have occurred since.

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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".

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

During fiscal year 2014, the Company achieved a number of key milestones in the strategy of creating value from our existing assets. Through the rationalization of non-core assets in Australia and the implementation of key projects, the Company now believes it is sufficiently capitalized to confirm the value potential of its core assets during fiscal year 2015.

In March 2014, the Company significantly increased its financial stability and streamlined the Company's operations through the sale of its Amadeus Basin gas fields to Central. Through this transaction, we were able to convert a non-core asset into liquid proceeds that can be redeployed on our core projects in the US and UK. In addition, this sale created numerous other benefits for us, including an 11% ownership stake in Central, the opportunity for substantial G&A savings with the closing of our Brisbane office, and a simpler focus and strategy for the Company. Soon after the sale, we also began efforts to farmout our Australian offshore block, NT/P82, which we expect to complete during fiscal year 2015. By moving into a non-operated position in this block through a farmout, we hope to significantly reduce or eliminate further capital commitments and dedication of management resources with respect to Australia, leaving us able to fully focus on Poplar in the US and the Weald Basin in the UK.

At Poplar, we committed our efforts throughout the entire fiscal year to the development of the CO_2-EOR pilot. The Company permitted the pilot wells, secured a contract for CO_2 supply during the pilot phase, drilled and completed five wells and installed surface facilities, and began the injection phase of the pilot program in March 2014. After addressing certain technical issues with the pilot and adjusting our well completion program to improve expected results, the CO_2-EOR pilot is now fully underway. We believe that data gathered during the early stages of the pilot through the date hereof support our thesis that CO_2-EOR development is both technically and economically feasible at Poplar. We look forward to further corroborating this position over the course of fiscal year 2015.

In the UK, during fiscal year 2014 the Company continued its strategy of pursuing unconventional development in the central Weald while finding partners to develop conventional prospects on the periphery of the basin. During the year, Magellan and its partner Celtique obtained a key extension to its central Weald licenses from June 2014 to June 2016. This extension will grant sufficient time to further establish the potential of the unconventional prospects of these licenses and to allow the surrounding political process and social environment to unfold. During the same period, Magellan and its partner Celtique advanced plans to drill a first exploratory well in the central Weald, which is expected to be spud at Broadford Bridge. Outside of the central Weald, we executed a farmout of the Horse Hill prospect, a conventional gas target, to Angus Energy ("Angus"). Pursuant to the terms of the farmout, Angus is obligated to fund 100% of the cost of drilling a vertical exploratory well in order to earn a 65% working interest in, and operatorship of, the license. This agreement allows Magellan to maintain exposure to this conventional play while limiting our investment of capital and management resources.

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SIGNIFICANT DEVELOPMENTS IN FISCAL YEAR 2014

During fiscal year 2014, the Company achieved a number of key milestones in the strategy of creating value from our existing assets.

Portfolio rationalization and funding of core projects

On March 31, 2014 (the "Central Closing Date"), pursuant to the Share Sale and Purchase Deed (the "Sale Deed") dated February 17, 2014 (the "Execution Date"), 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, to Central's wholly owned subsidiary Central Petroleum PV Pty. Ltd ("Central PV"). In exchange for the assets, Central paid to Magellan cash in the total amount of AUD $20.0 million, paid in two installments of AUD $15.0 million and AUD $5.0 million on March 31, 2014, and April 15, 2014, respectively, and 39.5 million newly issued shares of Central stock, worth AUD $15.0 million as determined on the Execution Date, equivalent to an approximate 11% ownership interest in Central as of the Central Closing Date. Magellan is currently Central's single largest shareholder. Based on the Central closing price on September 5, 2014, these shares of stock represent a total value of AUD $12.2 million, or an AUD $2.8 million decrease over the issuance value on the Execution Date. In addition, Magellan is entitled to receive bonus payments from Central in the event that future gas sales revenues from Palm Valley exceed certain levels. The Company also maintained its right to the Mereenie Bonus, which it received as part of the asset swap agreement with Santos QNT Pty Ltd ("Santos") in September 2011, and which entitles the Company to potential total cash payments ranging from AUD $5.0 million to AUD $17.0 million based on certain gas sales thresholds at Mereenie.

This transaction represents a major step in the rationalization of the Company's non-core assets. Furthermore, the Company expects that the consideration from the transaction, including the consideration received in the form of shares of Central's common stock, combined with the Company's previous cash balances provide the Company with sufficient funds to complete the CO_2-EOR pilot project at Poplar, to participate in the drilling of its first exploratory wells in the UK, and to finance its ongoing operations. By selling Dingo, the Company avoided the need to finance an AUD $20.0 million development, including necessary gas transportation facilities, which would have rendered the Australian operations cash flow negative over the next five years. The Company has also been able to close its Brisbane, Australia office, which is expected to reduce consolidated general and administrative expenses by approximately $2.0 million to $3.0 million per year and bring the Company closer to operating cash flow break-even levels. In addition, the 11% ownership stake in Central should allow the Company to maintain broader exposure to the Amadeus Basin through a player who controls most of the basin's acreage through farmouts to significant operators and represents an attractive investment opportunity with significant value appreciation potential.

For a summary of the key terms of the Sale Deed and further information on the Amadeus Basin Sale, please see the Company's Current Reports on Form 8-K filed with the SEC on February 18, 2014, and March 31, 2014.

Poplar CO_2-EOR pilot project

Fiscal year 2014 was a pivotal year for CO_2-EOR development at Poplar, during which period the Company finalized plans for, drilled five wells and installed the facilities for, and then began, the pilot program. In July 2013, the Company signed an approximate two-year CO_2 supply contract with Air Liquide for the purchase of CO_2 volumes necessary to complete the CO_2-EOR pilot project. In August 2013, the Company obtained permits from the US Bureau of Land Management to drill the five wells necessary for the pilot project. Between September and December 2013, the Company drilled all five pilot wells to total depth of approximately 5,800 feet. From January to March 2014, the Company completed and tested the wells and installed necessary surface facilities and CO_2 injection equipment. During this period, the Company collected various cores and logs, which contributed to a more refined 3-D reservoir model of the Charles formation at Poplar and will in turn improve our analysis of the performance of the CO_2-EOR pilot. At the end of March 2014, the Company began injecting CO_2 through the injection well, marking the beginning of the injection phase of the pilot. Between March and April 2014, the Company monitored and conducted preliminary tests of the effectiveness of CO_2 injection into the Charles formation. Between May and August 2014, the

Company paused CO_2 injection in order to (i) resolve issues that were identified with the cementing of the wells, (ii) amend and simplify the completion equipment design of the wells to address certain technical issues with packers and improve the overall reliability of the completion equipment, and (iii) perform water shut-off treatments on all of the pilot wells. Water shut-off treatments conducted in the pilot wells are identical to the treatments generally performed in other wells at Poplar and require approximately one month to complete. Their purpose is to enhance the amount of CO_2 injected in the reservoir matrix through the injection well and to block water production from fractures in the producer wells and enhance the amount of oil produced from the reservoir. In late August 2014, the Company began CO_2 injection once again.

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Based on the work completed to date, the Company has not identified any technical issues that would jeopardize the viability of CO_2-EOR at Poplar. Although results to date are very preliminary, the Company has already acquired critical data points that indicate that CO_2-EOR at Poplar could be technically viable. Initial CO_2 injection resulted in the relatively quick increase in down-hole pressures in the injector well bore to levels necessary, as determined by Core Labs in 2012, for the miscibility of CO_2 and oil at Poplar. This pressuring up indicated that CO_2 injection did not encounter a breakthrough, commonly called a "thief zone", through which CO_2 can by-pass the reservoir and thereby reduce the efficacy of the CO_2 in sweeping oil from the reservoir. Moreover, achieving miscibility pressure is essential for CO_2-EOR to be effective, and the ability to reach miscibility pressures relatively quickly implies that CO_2-EOR could be economically feasible at Poplar.

The Company has not yet opened the production wells. Once open, the primary production from these wells will provide a baseline against which we can measure the impact on production of CO_2 injection.

UK - Central Weald Licenses

During fiscal year 2014, the Company obtained a key extension to its central Weald licenses (PEDLs 231, 234, and 243), which it co-owns equally with Celtique Energie Holdings Ltd ("Celtique"). This extension should allow the Company sufficient time to establish the unconventional prospects in these licenses. Also during the period, Magellan and Celtique advanced plans to drill a first exploratory well on a conventional prospect at Broadford Bridge, located within the license area of PEDL 234, by the end of the second quarter of fiscal year 2015 depending on the finalization of the permitting process and rig availability.

In May 2014, the British Geological Survey ("BGS"), in association with the UK Department of Energy and Climate Change ("DECC"), publicly released a report (the "BGS Report") on the Jurassic shale formations in the Weald Basin. Maps presented in the BGS Report illustrate that the three licenses co-owned by Magellan cover most of the area prospective for unconventional development in the Weald Basin. In addition, tight conventional formations present between the thick shale packages of the Jurassic and Cretaceous sections may be prospective for development. These formations were previously tested with encouraging results by Cuadrilla at the Balcombe-1 well, which offsets Magellan’s central Weald licenses to the east.

UK - Peripheral Weald Licenses

During fiscal year 2014, the Company executed a farmout of PEDLs 137 and 246, which contain the Horse Hill prospect, to Angus Energy ("Angus"), a privately owned UK based exploration and development company. Pursuant to the terms of the farmout, Angus is obligated to fund 100% of the cost of drilling a vertical exploratory well in order to earn a 65% working interest in, and operatorship of, the license. The Horse Hill prospect was identified on 2-D seismic data reprocessed by the Company. The conventional hydrocarbon prospect, which is Triassic in age, is approximately 10,000 feet deep and is expected to primarily contain gas. Angus spud the Horse Hill-1 exploratory well in August 2014, and, as of the date hereof, the drilling of this well is ongoing. During the drilling of the Horse Hill-1 well, logs and cores are planned to be collected from the Kimmeridge and Liassic formations, which constitute the main potential unconventional formations in the Weald Basin and will contribute to the Company's overall understanding of the potential for unconventional development in the Weald Basin.

During the fiscal year, the Company also rationalized the portfolio of other licenses in which it owns interests on the periphery of the Weald Basin. Effective from March 2014, the Company, together with its partners in the respective licenses, relinquished PEDLs 155 and 256 due to a determination of limited development prospectivity within the license areas, and PEDL 240, which was located on the Isle of Wight, due to inability to secure a suitable drill site. In June 2014, PEDL 232, co-owned equally by Magellan and Celtique, was relinquished several weeks prior to its expiration date of June 30, 2014. The Company did not believe these licenses contained material hydrocarbon resources and did not consider them core to its UK strategy. The Company does not face abandonment or restoration liabilities with respect to these licenses.

With respect to PEDL 126, which contains the Markwells Wood-1 well, during fiscal year 2014 the Company and its partners contracted Schlumberger to undertake a study of the unconventional resource potential of the license area. This study indicated that the area is probably immature for oil or gas generation and therefore unlikely to have

unconventional shale oil or gas potential. This finding was consistent with the Company's understanding of the geology of the Basin.
Following the study, the joint venture reached an agreement with the DECC to relinquish all of the license area except for 11.2 square kilometers (2,768 acres) around and including the Markwells Wood-1 well bore in exchange for an extension of the exploration term by one year to June 30, 2015. During fiscal year 2015, the Company and its partners plan to evaluate the sale or farmout of the remaining license area to a third party on the basis of the relatively small conventional reservoir contained therein and the potential value of the wellbore to a third party. If the Company and its partners are unable to sell or farmout PEDL 126, the Company may face a plugging and abandonment liability of approximately $394 thousand net to its interest.

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OUTLOOK FOR FISCAL YEAR 2015

During fiscal year 2015, Magellan intends to continue executing on its strategy of proving the potential of its existing assets. The Company will be particularly focused on the following projects:

- progressing the CO_2-EOR pilot project at Poplar to such a point that the Company will be able to assess the technical and economic viability of a full CO_2-EOR program at the field;
- drilling one and possibly two wells in the UK to evaluate the potential of the various conventional and unconventional formations in our licenses there; and
- executing a farmout of NT/P82 to a partner qualified in offshore drilling that will result in the drilling of at least one test well over the license area by May 2016.

The Company believes that each of these projects has significant potential that, if realized, could materially impact the Company's reserves and the underlying net asset value per share and eventually allow the Company to generate positive cash flow from operations and raise financing on attractive terms. Specific steps and milestones for each of these key areas are discussed below. By pursuing these courses of action in parallel, the Company expects that, over the next 12 months, it will be able to validate the value potential of these assets and will be able to determine the most appropriate course of action with respect to each asset to achieve the best value for its shareholders.

CO_2-EOR Pilot Project

During fiscal year 2015, the Company will continue to conduct the CO_2-EOR pilot at Poplar with the objective of obtaining meaningful preliminary results in the third quarter of fiscal year 2015. Following implementation of improvements in well completion design and surface facility injection systems and the re-initiation of CO_2 injection during the summer of 2014, CO_2 injection is expected to be continuous over the coming months. The Company will also soon open for production the four pilot producer wells. Once open, the primary production from these wells will provide a baseline against which we can measure the impact on production of CO_2 injection. Over the upcoming months, the Company will be continuously monitoring key data in real-time, including CO_2 injection pressures, volumes, and rates, and production from the producer wells. The Company will then integrate this data into its 3-D reservoir model to enhance its interpretation of the reservoir and its understanding of the efficacy of CO_2-EOR at Poplar.

With these results, and with additional data from the pilot to be received over the remainder of the fiscal year, the Company anticipates that it will be able to quantify with greater certainty the incremental volume of oil that could be recoverable from Poplar through the use of CO_2-EOR techniques, and the corresponding increase in the quantity of reserves the Company can record with respect to CO_2-EOR.

UK - Central Weald Licenses

In fiscal year 2015, the Company will work with its partner, Celtique, to spud the Broadford Bridge-1 well, the first exploratory well in the Central Weald licenses. The Broadford Bridge-1 well is designed and permitted to test a conventional prospect in a Triassic-age formation, similar to the prospect targeted at Horse Hill. The Company and its partner Celtique also intend to collect logs and cores, where appropriate, from the Kimmeridge and Liaissic formations, which hold potential for unconventional development. According to an agreement with the DECC, this well, which is located within the license area of PEDL 234, will satisfy the drilling obligations for both PEDLs 234 and 243. Currently, the process of obtaining relevant regulatory and planning permissions is substantially complete, and the timing of spudding this well will depend primarily on rig availability. Currently, the Company expects the well to be spud late in the second or early in the third quarter of fiscal year 2015.

In parallel, the Company will continue efforts with Celtique to permit additional drilling locations within the Central Weald licenses. The Company expects that it can permit well sites successfully such that it can meet its drilling obligations for these licenses within the required time frame of before June 30, 2016. Although the UK regulatory and permitting process can be challenging, particularly with respect to locally granted permits, the UK government has made significant efforts to improve the efficiency of such processes with various proposed changes to incentive schemes, regulatory processes, and laws relevant to onshore unconventional oil and gas development. The Company expects that such proposed changes will become effective during fiscal year 2015.

During fiscal year 2015, there are a number of wells scheduled to be drilled onshore in the UK by other industry players, some of which will be hydraulically fractured. As these various new wells are permitted and drilled, the Company expects that the permitting and regulatory processes will become smoother and more efficient.

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UK - Peripheral Weald Licenses
On September 3, 2014, Angus commenced drilling operations on the Horse Hill-1 well. The well is expected to be drilled to a depth of approximately 8,700 feet and to test a number of Jurassic-aged conventional stacked oil formations, including the Portland Sandstone, Corallian Sandstone, and Great Oolite formations, and a Triassic-aged conventional gas target. The well will be drilled vertically and will not be hydraulically fractured. The Horse Hill-1 well lies within the license area of PEDL 137. Pursuant to a farmout agreement executed in December 2013, Horse Hill Development Limited, a majority-owned subsidiary of Angus Energy, will carry Magellan for its share of the costs of this well in exchange for having received operatorship of, and a 65% interest in, both the well and the license. During drilling, Magellan will have the opportunity to core and log at its own expense several shale and tight formations in the Cretaceous and Jurassic sections, including the Kimmeridge Clay and Liassic formations. The Company expects that the information gained through these activities will provide valuable insights into the technical and economic viability of unconventional development elsewhere in the Weald Basin.
With respect to the Company's interests in its two other licenses on the periphery of the Weald Basin, P1916 and PEDL 126, the Company currently has no plans to pursue exploration or drilling activities. The Company does not believe that a suitable drilling location can be permitted for P1916. As such, the Company is considering, together with its joint venture partners, the relinquishment of this license. During fiscal year 2015, the Company and its partners in PEDL 126 will evaluate the sale or farmout of the remaining license area to a third party on the basis of the relatively small conventional reservoir contained therein.
During fiscal year 2015, the UK government will hold the 14th Annual Landward Licensing Round, through which companies will be able to apply for various oil and gas exploration permits onshore in the UK. Magellan does not intend to participate in this round, since we believe that our central Weald licenses cover substantially all of Weald Basin's acreage prospective for unconventional development, and we have not identified attractive conventional targets in other areas.

NT/P82, Offshore Australia
Based on the results of 2-D and 3-D seismic interpretation completed in fiscal year 2014, the Company began a process in the fourth quarter of fiscal year 2014 to identify a farmout partner experienced in offshore drilling. In completing a 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 drill exploration wells by May 2016 over the large gas prospects identified in the block. 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 2015.

SUMMARY RESULTS OF OPERATIONS FOR THE YEAR ENDED JUNE 30, 2014
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 figures presented immediately below for fiscal years 2013 and 2014 exclude the impact of these assets on such figures.
Revenues. Revenues for the year ended June 30, 2014, totaled $7.6 million, compared to $6.1 million in the prior year, an increase of 24%. The $1.5 million increase in revenue over the prior year was primarily due to both an increase in production volumes ($1.2 million) resulting from the favorable impact of workovers and water shut-off treatments on several wells during the year, and an increase in WTI benchmark pricing ($0.7 million), which increases were partially offset by a decrease in the pricing differential realized at Poplar ($0.4 million).
Net Income and Earnings per Share. Net income totaled $13.8 million ($0.30/basic share), compared to a net loss of $20.5 million ($(0.41)/basic share) in the prior year. The increase in net income was primarily the result of a gain on sale of assets of $30.0 million recognized as a result of the sale of the Amadeus Basin assets in March 2014.
Adjusted EBITDAX. Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) totaled negative $5.6 million, compared to negative $7.5 million in the prior year, a change of 26%. The improvement in Adjusted EBITDAX resulted from an increase in revenues of $1.5 million

and a reduction in general

and administrative expense (excluding stock based compensation and foreign transaction loss) of $1.9 million, partially offset by an increase in lease operating expense of $1.4 million.

Cash. As of June 30, 2014, Magellan had $16.4 million in cash and cash equivalents, compared to $32.5 million at the end of the prior fiscal year. The decrease of $16.0 million was the result of net cash used in operating activities of $11.7 million, net cash used in investing activities of $2.4 million, net cash used in financing activities of $0.7 million, and net cash used in discontinued operations of $1.4 million, offset by a $0.1 million increase in cash from the effect of exchange rates. The $2.4 million of net cash used in investing activities was the result of $20.9 million of capital expenditures primarily relating to the CO_2-EOR pilot at Poplar, partially offset by $18.6 million in proceeds from the sale of the Company's Amadeus Basin assets.

Securities available-for-sale. As of June 30, 2014, Magellan had $11.9 million in securities available for sale, consisting primarily of the Company's investment in the 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

Historically, we have funded our activities from cash from operations, asset sales, farmout agreements, an issuance of preferred equity, and our existing cash balance. Based on (i) our existing cash position, including the cash received from the sale of the Company's Amadeus Basin assets in fiscal year 2014; (ii) the flexibility in the implementation and timing of various operational projects; (iii) the ability to implement and/or raise additional funds from farmout transactions and/or partial or complete sales of certain of our international assets; and (iv) the potential to raise funds from debt and equity financings; the Company believes it has sufficient financial resources to fund its ongoing operations and its exploration projects, including the remainder of the CO_2-EOR pilot project and the participation in the drilling of exploratory wells in the UK.

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. Currently, Poplar contains 34 productive wells. In the Shallow Intervals, which are 100% owned and operated by the Company, discretionary capital expenditure plans over the next two years will be determined primarily by the results of the CO_2-EOR pilot project, which is expected to continue through December 2015. The total cost of the CO_2-EOR pilot, including capital expenditures and certain operating expenses, is estimated at approximately $26.0 million, which amount includes approximately $4.0 million related to the cost of purchasing sufficient volumes of CO_2 over a two year period. As of June 30, 2014, the Company has incurred approximately $19.1 million in relation to the CO_2-EOR pilot and expects that, in total, a further $6.9 million will be required to both complete all the wells (approximately $2.9 million) and inject sufficient volumes of CO_2 (approximately $4.0 million). The final cost of the injected volumes of CO_2 will depend on the total amount injected. Additionally, the Company will incur capital expenditures related to water shut-off treatments, workovers and drilling of certain newly identified PUD locations.

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 2015.

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. The Company is currently focused on securing potential drilling locations, applying for drilling permits, preparing to drill the Broadford Bridge-1 well, and evaluating the potential of its unconventional prospects in these licenses. The Company expects to fund its share of the cost related to the Broadford Bridge-1 well, currently estimated to be approximately $5.0 million. The Company is also considering other options to fund its share of the drilling cost of the Broadford Bridge-1 well, which include a potential partial or full farmout transaction. This well will meet the drill-or-drop obligations for both PEDLs 234 and 243. Pending the results of this well, the Company may participate in a second exploratory well within these PEDLs in fiscal year 2016.

In the Bonaparte Basin, offshore Australia, the Company holds a 100% interest in NT/P82. Under the terms of the permit, the Company is required to drill one exploratory well on the license by May 2016. Following the successful completion of seismic surveys in the license area and the associated processing and interpretation, the Company is actively engaged in a farmout process to identify a partner experienced in offshore exploratory drilling to drill at least one exploratory well on our behalf. The Company does not expect to incur further significant capital expenditures of its own until after the first exploration well has been drilled.

Series A preferred dividend. Based on the Series A Preferred Stock shares outstanding at June 30, 2014, and assuming that the Company will elect to pay in cash the dividend that holders of Series A preferred stock are entitled to, the total amount of the dividend for fiscal year ending June 30, 2015, is estimated to amount to approximately $1.7 million. As long as the Company's share price is materially higher than the Conversion Price of $1.22149381, the Company intends to pay the preferred dividend in cash. The Company may decide to issue shares of common stock to finance the dividend, which would represent a positive arbitrage between the Conversion Price and the issuance price of the newly issued common shares.

Discontinued Operations. As a result of the sale of the Amadeus Basin Assets, the Company will be able to avoid development costs at Dingo of approximately AUD $20.0 million, including necessary gas transportation facilities, which would have rendered the Australian operations cash flow negative over the next five years. In addition, the closing of the Brisbane office in April 2014 should result in reduced consolidated general and administrative expenditures of approximately $2.0 million to $3.0 million per year.

Contractual Obligations. The following table summarizes our obligations and commitments as of June 30, 2014, 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	$2,873	$397	$—	$—	$2,476
Contingent consideration payable [(1)]	1,852	—	1,852	—	—
Operating leases	893	262	541	90	—
Total	$5,618	$659	$2,393	$90	$2,476

[(1)] Assumptions for the timing of these payments are based on our reserve report and planned drilling activity.

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 of $2.0 million in shares of its common stock. As of June 30, 2014, $1.9 million remained authorized for stock repurchases under this program. This program expired on August 21, 2014. See Issuer Purchases of Equity Securities under Part II, Item 5 of this report for additional information.

Sources of Funds

Cash and Cash Equivalents. On a consolidated basis, the Company had approximately $16.4 million of cash and cash equivalents at June 30, 2014, compared to $32.5 million as of June 30, 2013. As of June 30, 2014, $4.3 million and $1.9 million of the Company's consolidated cash and cash equivalents were deposited in accounts held by MPUK and MPA, respectively, all of which was held in bank accounts and time deposit accounts having terms of 90 days or less. During fiscal year 2014, the Company repatriated approximately $11.1 million in the form of distributions from MPA to MPC at a weighted average AUD:USD exchange rate of 0.9361. These distributions are not expected to result in any cash tax expenditures. 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 their maturity that they present insignificant risk of changes in value because of changes in interest rates.

Due to the international nature of its operations, the Company is exposed to 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 MPA 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.

Existing Credit Facilities. As of June 30, 2014, the Company had no outstanding borrowings and had no undrawn credit facilities. The Company, through its wholly owned subsidiary NP, maintained a credit facility with Jonah Bank of Wyoming through June 2014. As of June 30, 2014, the facility had been repaid in full and canceled according to its term of expiry. On September 17, 2014, the Company entered into a Line of Credit facility with West Texas State Bank, which allows the Company to borrow up to $8.0 million at a floating interest rate equivalent to Prime, which is currently 3.25%. This facility will give the Company the ability to finance some of its activity at Poplar, including the implementation of water shut-off treatments on certain wells.

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Central Shares. Based on the Company's current balance sheet position, the expected costs of its current projects, and the potential value appreciation of Central's shares, the Company currently intends to continue holding its position in Central's stock. The Company is not constrained in its ability to sell its shares in Central by contractual arrangements with Central. In the future, Magellan may decide to dispose of part or all of its position in Central's stock to fund some of the Company's activities. Based on the Central closing price on September 5, 2014, these shares of stock represent a total value of AUD $12.2 million, or an AUD $2.8 million decrease over the issuance value on the Execution Date.
Other Sources of Financing. In addition to its existing liquid capital resources the Company has various alternatives to fund the development of its assets. These alternatives could potentially include conventional bank debt, a reserve-based loan facility, a project finance loan facility, 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.

Cash Flows

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

	June 30, 2014	2013
	(In thousands)	
Cash (used in) provided by:		
Operating activities	$(11,668)	$(17,265)
Investing activities	(2,369)	(2,732)
Financing activities	(680)	12,357
Discontinued operations	(1,443)	(958)
Effect of exchange rate changes on cash and cash equivalents	113	(148)
Net decrease in cash and cash equivalents	$(16,047)	$(8,746)

Cash used in operating activities during the year ended June 30, 2014, was $11.7 million, compared to cash used of $17.3 million in 2013. The decrease in cash used in operating activities primarily resulted from a combination of an increase in revenues of $1.5 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, 2014, was $2.4 million, compared to cash used of $2.7 million in 2013. 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. This amount was offset by $20.9 million of capital expenditures spent on the development of our assets. The increase in cash used in investing activities was due to the capital expenditures related primarily to the CO_2-EOR pilot project at Poplar.
Cash used in financing activities during the year ended June 30, 2014, was $0.7 million, compared to cash provided of $12.4 million in 2013. Cash used in financing activities primarily related to the repayment of short term debt and increased in fiscal year 2014 as a result of prior year proceeds of $23.0 million from issuing preferred stock, partially offset by the repurchase of common stock and warrants from Sopak in the amount of $10.1 million.
Cash used in discontinued operations is related to the activities of Palm Valley and Dingo. No continuing impact on cash flows is expected from discontinued operations.
During the year ended June 30, 2014, the effect of changes in foreign currency exchange rates positively impacted the translation of our GBP and AUD denominated cash and cash equivalent balances into US dollars and resulted in an increase of $113 thousand in cash and cash equivalents, compared to a decrease of $148 thousand in 2013.

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COMPARISON OF FINANCIAL RESULTS AND TRENDS BETWEEN FISCAL 2014 AND 2013

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

	June 30, 2014	2013	Difference	Percent change
Poplar:				
Oil revenue (In thousands)	$7,601	$6,131	$1,470	24 %
Oil sales volume (Mbbls)	88	72	16	22 %
Oil sales volume (boepd)	241	197	44	22 %
Average realized oil price ($/boe)	$86.38	$84.91	$1.47	2 %

Oil Revenue

Revenues for the year ended June 30, 2014, totaled $7.6 million, compared to $6.1 million in the prior year, an increase of 24%. The $1.5 million increase in revenue over the prior year was primarily due to the increased production volume.

Oil Sales Volume

Sales volume for the year ended June 30, 2014, totaled 88 Mbbls (241 boepd), compared to 72 Mbbls (197 boepd) sold in the prior year, an increase of 22%. The increase was primarily the result of increased production from water shut-off treatments and workovers.

Average Realized Oil Price

The average realized price for the year ended June 30, 2014, was $86.38/boe, compared to $84.91/boe in the prior year, an increase of 2%. The increase was primarily the result of decreasing differentials relative to the benchmark pricing (WTI) 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, 2014 (In thousands)	2013	Difference	Percent change
Selected operating expenses:				
Lease operating	$6,257	$4,851	$1,406	29 %
Depletion, depreciation, amortization, and accretion	$1,123	$1,121	$2	*
Exploration	$3,484	$7,907	$(4,423)	(56)%
General and administrative	$9,085	$9,645	$(560)	(6)%
Selected operating expenses ($/boe):				
Lease operating	$71	$67	$4	6 %
Depletion, depreciation, amortization, and accretion	$13	$16	$(3)	(19)%
Exploration	$40	$110	$(70)	(64)%
General and administrative	$103	$134	$(31)	(23)%

(*) Not meaningful.

Lease Operating Expenses. Lease operating expenses increased by $1.4 million to $6.3 million, or $71/boe, during the year ended June 30, 2014. The increase is related to increased production tax due to increased production, increased workover activity and significant road repairs.

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

	June 30, 2014	2013	Difference	Percent change
	(In thousands)			
Depreciation and amortization	$210	$196	$14	7 %
Depletion	749	768	(19)	(2)%
ARO accretion [1]	164	157	7	4 %
Total	$1,123	$1,121	$2	*

[*] Not meaningful.
[1] Accretion expense related to continuing operations.
Depletion, depreciation, amortization, and accretion expenses increased by $2 thousand to $1.1 million, or $13/boe, during the year ended June 30, 2014.
Exploration Expenses. Exploration expenses decreased by $4.4 million to $3.5 million, or $40/boe, during the year ended June 30, 2014. The Company allowed petroleum exploration and development licenses in the amount of $0.7 million in the UK to expire at the end of their term, compared to the prior year write off of $2.2 million of the Company's interest in the Markwells Wood-1 well in the UK, which resulted from the Company's determination that it had no further development plans with respect to this well. Most of the $3.5 million was incurred in relation to the licenses operated by Celtique in the UK and primarily represent timewriting by consultants and long term lead analysis by geologists and other geological expenses related to the PEDL 234 in the UK. Exploration expense during the prior fiscal year included $3.7 million incurred for seismic activities over the NT/P82 license area in Australia.

General and Administrative Expenses. The following table presents general and administrative expenses for the fiscal years ended:

	June 30, 2014	2013	Difference	Percent change
	(In thousands)			
General and administrative (excluding stock based compensation and foreign transaction loss)	$6,912	$8,778	$(1,866)	(21)%
Stock based compensation	2,009	848	1,161	137 %
Foreign transaction loss	165	18	147	817 %
Total	$9,085	$9,645	$(558)	(6)%

General and administrative expenses decreased by $0.6 million to $9.1 million, during the year ended June 30, 2014. General and administrative expenses, excluding stock based compensation and foreign transaction losses, amounted to $6.9 million, a decrease of $1.9 million. This decrease primarily resulted from a $0.8 million reduction in non-recurring severance benefits from the prior year, a $0.5 million decrease in legal and professional services, a $0.3 million decrease in travel expenditures and a decrease of $0.2 million related to director costs. The increase in non-cash stock based compensation expense is primarily related to the recent issuance of equity based compensation awards to officers and employees, and to non-employee directors pursuant to the terms of the Company's compensation policy related to their annual base compensation for Board service. Foreign transaction loss is expected to be minimal in the future.

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 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

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policies, estimates, and judgments made by management in Note 1 to our consolidated financial statements. 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 is 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 reserves estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserves 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 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 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 net discounted future cash flows from the producing property. Different pricing assumptions (see Note 19) or discount rates could result in a different calculated impairment.

Asset Retirement Obligation. 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 PBOs and time based stock options using the Black-Scholes-Merton pricing model. The fair value for market based stock options is estimated using Monte Carlo simulation techniques. These valuation methods use 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 time based stock options are recognized as an expense on a straight-line basis over the requisite service period, which is generally the vesting period. Market based options are expensed based on a graded amortized method, the expense is recognized if the derived service period is satisfied, even if the market condition is not achieved. Performance based options are recognized over the performance period when the achievement of the performance conditions is considered probable. Management re-assesses whether satisfaction of performance conditions are probable at the end of each reporting period. As of June 30, 2014, 2,175,000 stock options with market based vesting provisions or PBOs were outstanding. 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, 2014.

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 fiscal 2014, all remaining investments and intercompany transactions continue to be considered long term in nature, and as a result, all foreign currency translation adjustments were recorded as a separate component of stockholders' equity as accumulated other comprehensive income (loss).

Accounting for Business Combinations

The Company continues to 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 utilized 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, 2014, oil sales represented 100% of total oil and gas revenues. Based on fiscal year 2014 sales volume and revenues, a 10% change in oil price would increase or decrease oil revenues by $0.8 million.

At June 30, 2014, the fair value of our investments in securities available-for-sale was $11.9 million, with $11.9 million 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, 2014, of AUD $0.320 per share, which translated to $0.301 per share in US dollars on that date. 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 elect to 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 $1.2 million change in the fair value of our investments.

At June 30, 2014, the carrying value of cash and cash equivalents was approximately $16.4 million, which approximates the fair value.

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 addresses 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," "estimate," "expect," "forecast," "initial," "plan,"

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"potential," "project," "will," 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 capital expenditures, 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, 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 recently initiated 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; 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 and through uncertain estimates of annual savings in general and administrative expenses; 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 operational 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 fractures that could affect our ability to develop unconventional resource projects in the UK; the uncertain nature of oil and gas prices in the US, UK, and the Australia; uncertainties inherent in projecting future rates of production from drilling and CO_2-EOR activities; 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; 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. 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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for the years ended June 30, 2014 and 2013. 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, 2014 and 2013, and the results of their operations and their cash flows for the years ended June 30, 2014 and 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ EKS&H LLLP
Denver, Colorado
September 18, 2014

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

	June 30, 2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$16,422	$32,469
Securities available-for-sale	11,935	44
Accounts receivable — trade	886	852
Inventories	739	555
Prepaid and other assets	2,105	1,378
Total current assets	32,087	35,298
PROPERTY AND EQUIPMENT, NET (SUCCESSFUL EFFORTS METHOD):		
Proved oil and gas properties	29,335	35,377
Less accumulated depletion, depreciation, amortization, and accretion	(3,575)	(5,814)
Unproved oil and gas properties	550	5,312
Wells in progress	21,296	923
Land, buildings, and equipment (net of accumulated depreciation of $483 and $1,810 as of June 30, 2014, and 2013, respectively)	368	1,382
Net property and equipment	47,974	37,180
OTHER NON-CURRENT ASSETS:		
Goodwill	1,174	2,174
Deferred income taxes	—	7,217
Other long term assets	200	403
Total other non-current assets	1,374	9,794
Total assets	$81,435	$82,272
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Short term line of credit	$—	$51
Current portion of note payable	—	390
Current portion of asset retirement obligations	397	476
Accounts payable	3,586	1,948
Accrued and other liabilities	2,121	2,757
Accrued dividends	429	202
Total current liabilities	6,533	5,824
LONG TERM LIABILITIES:		
Asset retirement obligations	2,476	6,403
Contingent consideration payable	1,852	3,940
Other long term liabilities	118	163
Total long term liabilities	4,446	10,506

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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 20,089,436 and 19,239,734 shares as of June 30, 2014, and 2013, respectively; liquidation preference of $28,220 and $27,227, respectively	24,539	23,502
Total preferred stock	24,539	23,502
EQUITY:		
Common stock (par value $0.01 per share): Authorized 300,000,000 shares, issued, 55,004,838 and 54,057,159 as of June 30, 2014, and 2013, respectively	550	540
Treasury stock (at cost): 9,425,114 and 9,414,176 shares as of June 30, 2014 and 2013, respectively	(9,344)	(9,333)
Capital in excess of par value	92,986	90,786
Accumulated deficit	(36,266)	(50,079)
Accumulated other comprehensive (loss) income	(2,009)	10,526
Total equity attributable to common stockholders	45,917	42,440
Total liabilities, preferred stock and equity	$81,435	$82,272

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,	
	2014	2013
REVENUE FROM OIL PRODUCTION	$7,601	$6,131
OPERATING EXPENSES:		
Lease operating	6,257	4,851
Depletion, depreciation, amortization, and accretion	1,123	1,121
Exploration	3,484	7,907
General and administrative	9,085	9,645
Impairment	—	890
Total operating expenses	19,949	24,414
Loss from operations	(12,348)	(18,283)
OTHER (EXPENSE) INCOME:		
Net interest (expense) income	(243)	298
Fair value revision of contingent consideration payable	2,403	458
Other income	146	698
Total other income	2,306	1,454
Loss from continuing operations	(10,042)	(16,829)
DISCONTINUED OPERATIONS:		
Loss from discontinued operations, net of tax	(4,461)	(2,938)
Gain on disposal of discontinued operations, net of tax	30,012	—
Net income (loss) from discontinued operations	25,551	(2,938)
Net income (loss) attributable to Magellan Petroleum Corporation	15,509	(19,767)
Preferred stock dividends and accretion of preferred stock	(1,696)	(722)
Net income (loss) attributable to common stockholders	$13,813	$(20,489)
Earnings per common share (Note 12):		
Weighted average number of basic shares outstanding	45,348,840	49,642,083
Weighted average number of diluted shares outstanding	45,348,840	49,642,083
Basic earnings (loss) per common share:		
Loss from continuing operations	$(0.26)	$(0.35)
Net income (loss) from discontinued operations	$0.56	$(0.06)
Net income (loss) attributable to common stockholders	$0.30	$(0.41)
Diluted earnings (loss) per common share:		
Loss from continuing operations	$(0.26)	$(0.35)
Net income (loss) from discontinued operations	$0.56	$(0.06)
Net income (loss) attributable to common stockholders	$0.30	$(0.41)

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,	
	2014	2013
Net income (loss) attributable to Magellan Petroleum Corporation	$15,509	$(19,767)
Other comprehensive loss, net of tax:		
Foreign currency translation gain (loss)	488	(569)
Reclassification of foreign currency translation gain to earnings upon sale of foreign subsidiary	(5,767)	—
Unrealized holding losses on securities available-for-sale	(7,256)	(112)
Other comprehensive loss, net of tax	(12,535)	(681)
Comprehensive income (loss) attributable to Magellan Petroleum Corporation	$2,974	$(20,448)

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	Common Stock Amount	Capital in Excess of Par Value	Treasury Stock	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Stockholders' Equity
Fiscal year ended June 30, 2012	53,835,594	$ 538	$ 90,753	$ —	$ (29,590)	$ 11,207	$ 72,908
Net loss	—	—	—	—	(19,767)	—	(19,767)
Other comprehensive loss, net of tax	—	—	—	—	—	(681)	(681)
Stock and stock based compensation	221,565	2	846	—	—	—	848
Common stock repurchased	—	—	—	(9,333)	—	—	(9,333)
Warrants repurchased and retired	—	—	(813)	—	—	—	(813)
Preferred stock accretion to fair value	—	—	—	—	(520)	—	(520)
Preferred stock dividend	—	—	—	—	(202)	—	(202)
Fiscal year ended June 30, 2013	54,057,159	540	90,786	(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	716,664	7	2,002	—	—	—	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	231,015	3	198	—	—	—	201
Preferred stock dividend	—	—	—	—	(1,696)	—	(1,696)
Fiscal year ended June 30, 2014	55,004,838	$ 550	$ 92,986	$ (9,344)	$ (36,266)	$ (2,009)	$ 45,917

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,	
	2014	2013
OPERATING ACTIVITIES:		
Net income (loss) attributable to Magellan Petroleum Corporation	$15,509	$(19,767)
Adjustments to reconcile net loss to net cash used in operating activities:		
Foreign transaction loss	165	18
Depletion, depreciation, amortization, and accretion	1,123	1,121
Fair value revision of contingent consideration payable	(2,403)	(458)
Accretion expense of contingent consideration payable	315	326
Gain on disposal of Amadeus Basin assets	(30,012)	—
Exploration costs previously capitalized	733	2,299
Stock based compensation	2,009	848
Impairment loss	—	890
Severance benefit costs	—	418
Net changes in operating assets and liabilities:		
Accounts receivable	52	84
Inventories	(184)	(47)
Prepayments and other current assets	(694)	82
Accounts payable and accrued liabilities	1,719	(3,079)
Net cash used in operating activities	(11,668)	(17,265)
INVESTING ACTIVITIES:		
Additions to property and equipment	(20,923)	(2,732)
Proceeds from Amadeus Basin sale	18,554	—
Net cash used in investing activities	(2,369)	(2,732)
FINANCING ACTIVITIES:		
Proceeds from issuance of common stock	201	—
Repurchase of common stock	(11)	(9,333)
Repurchase of warrant	—	(813)
Proceeds from issuance of preferred stock, net of $520 issuance cost	—	22,982
Short term debt issuances	1,000	2,000
Short term debt repayments	(1,441)	(1,999)
Long term debt repayments	—	(480)
Payment of Preferred stock dividend	(429)	—
Net cash (used in) provided by financing activities	(680)	12,357

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CASH FLOWS FROM DISCONTINUED OPERATIONS:		
Net cash used in operating activities of discontinued operations	(31)	(766)
Net cash used in investing activities of discontinued operations	(1,412)	(192)
Net cash used in discontinued operations	(1,443)	(958)
Effect of exchange rate changes on cash and cash equivalents	113	(148)
Net decrease in cash and cash equivalents	(16,047)	(8,746)
Cash and cash equivalents at beginning of period	32,469	41,215
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$16,422	$32,469
Cash (receipts) payments:		
Interest paid	$18	$63
Interest received	$(102)	$(698)
Supplemental schedule of non-cash investing and financing activities:		
Preferred stock dividends paid in kind	$1,037	$—
Securities available-for-sale received upon sale of Amadeus Basin assets (Note 3)	$19,147	$—
Unrealized holding loss on securities available-for-sale	$(7,256)	$(112)
Revision to estimate of asset retirement obligation	$—	$(758)
Accounts payable related to capital expenditure	$846	$81
Accrued preferred stock dividends	$429	$202
Accretion of preferred stock to fair value	$—	$520
Amounts in accrued and other liabilities related to Sopak (See Note 14)	$1,571	$1,000
Amounts in prepaid and other assets related to Sopak (See Note 14)	$1,571	$1,000

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

MAGELLAN PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 - Basis of Presentation
Description of Operations
Magellan Petroleum Corporation (the "Company" or "Magellan" or "we") is an independent oil and gas exploration and production company focused on the development of a CO_2-enhanced oil recovery ("CO_2-EOR") program at Poplar Dome ("Poplar") in eastern Montana and the exploration of conventional and unconventional hydrocarbon resources in the Weald Basin, located in Sussex County, England, onshore United Kingdom ("UK"). Magellan also owns an exploration block, NT/P82, in the Bonaparte Basin, offshore Northern Territory, Australia, which the Company currently plans to farmout; and an 11% ownership stake in Central Petroleum Limited (ASX: CTP), a Brisbane based 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 geographic 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.

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 are in US dollars, unless otherwise noted. Amounts expressed in Australian currency are indicated as "AUD."

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 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 income, a separate component of stockholders' equity. 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.
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.

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. Cash and cash equivalents are held in several UK and Australian bank accounts and time deposit accounts

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that have terms of 90 days or less. The Company regularly assesses the level of credit risk we are exposed to and whether there are better ways 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 income in stockholders' equity, net of deferred income taxes. The Company recognizes gains or losses when securities are sold. On a quarterly basis, we perform 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. As a result of this review, no impairment was recorded for the years ended June 30, 2014, or 2013, respectively.

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, 2014, and 2013, respectively.

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 noncommercial. If an exploratory well is deemed to be noncommercial, the well costs are charged to exploration expense as dry hole cost. Exploration expenses include dry hole costs, geological and geophysical expenses. Noncommercial development well costs are charged to impairment expense if circumstances indicate that a decline in the recoverability of the carrying value may have occurred.

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 anticipated proceeds from salvaging equipment. The Company records its proportionate share in joint venture operations in the respective classifications of assets, liabilities, and expenses.

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 and is included in the accompanying consolidated statements of operations.

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

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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, 2014 and 2013, management concluded that there is no impairment of goodwill. The qualitative factors used in our assessment include macroeconomic conditions, industry and market conditions, cost factors, and overall financial performance.

As of June 30, 2014, $0.7 million of recorded goodwill related to NP, $0.2 million related to MPUK, and $0.3 million related to MPA. Changes in goodwill can be summarized as follows for the years ended:

	June 30,	
	2014	2013
	(In thousands)	
Fiscal year opening balance	$2,174	$2,174
Sale of Amadeus Basin assets (see Note 3)	(1,000)	—
Fiscal year closing balance	$1,174	$2,174

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).

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 collectability of the revenue is probable. Transportation costs are included in production costs.

Major Customers

The Company's consolidated oil production revenue is derived from its NP segment and is generated from a single customer for the years ended June 30, 2014, and 2013, respectively.

Stock Based Compensation

Stock option grants may contain time based, market based, or performance based vesting provisions. Time based options are expensed on a straight-line basis over the vesting period. Market based options are expensed based on a graded amortization method, the expense is recognized if the derived service period is satisfied, even if the market condition is not achieved. Performance based options ("PBOs") are recognized when the achievement of the performance conditions is considered probable. Accordingly, PBOs are expensed over the period of time 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 market based stock options, 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, 2014, or 2013, 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.

Segment Information

As of June 30, 2014, 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, 2014, 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.

Earnings (Loss) 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 effect of potential 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.

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The potential dilutive impact of stock options, and non-vested restricted stock is determined using the treasury stock method. The potential dilutive impact of the shares of Series A convertible 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 antidilutive. 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 convertible preferred stock in the calculation of diluted earnings (loss) per share during the fiscal year ended June 30, 2014, and 2013, respectively, as they would be antidilutive.

Accumulated Other Comprehensive Income (Loss)

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

Recently Issued Accounting Standards

In February 2013, the FASB issued Accounting Standards Update ("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.

In May 2014, the FASB issued ASU 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 will be effective for us in the first quarter of our fiscal year 2018; early adoption is not permitted. The Company is currently evaluating which transition approach to use and the impact of the adoption of this standard 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, 2014.

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 Petroleum Limited ("Central") through the sale of the Company's wholly owned subsidiary, Magellan Petroleum (N.T.) Pty. Ltd, to Central's wholly owned subsidiary Central Petroleum PV Pty. Ltd ("Central PV"). In exchange for the assets, on March 31, 2014, Central paid to Magellan (i) a first cash payment of AUD $15.0 million, and (ii) 39.5 million newly issued shares of Central stock (ASX: CTP), equivalent to an ownership interest in Central of approximately 11%. Central also made a second and final cash payment of AUD $5.0 million to Magellan on April 15, 2014. The Sale Deed provides for certain customary purchase price adjustments, including the payment by Central of capital expenditures incurred by Magellan during the period

from October 1, 2013, and March 31, 2014, less AUD $485 thousand.
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

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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 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. Prior year amounts related to discontinued operations in the consolidated statements of operations and statements of cash flows have also been reclassified to conform to the current year presentation. Summarized results of the Company's discontinued operations are as follows:

	June 30,	
	2014	2013
	(In thousands)	
Revenue	$814	$939
Loss from discontinued operations, net of tax	$(4,461)	$(2,938)

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

	June 30,	
	2014	2013
	(In thousands)	
Assets and liabilities sold:		
Property and equipment, net	$(10,100)	$(9,627)
Deferred income taxes	(7,217)	(7,217)
Goodwill allocated to the disposal group	(1,000)	(1,000)
Asset retirement obligations	4,457	4,575
Purchase price adjustments	743	—
Total assets and liabilities of discontinued operations	(13,117)	(13,269)
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, 2014			
	Amortized cost	Gross unrealized gains	Gross unrealized losses	Fair value
	(In thousands)			
Equity securities	$19,339	$—	$(7,404)	$11,935

	June 30, 2013			
	Amortized cost	Gross unrealized gains	Gross unrealized losses	Fair value
	(In thousands)			
Equity securities	$192	$—	$(148)	$44

Note 5 - Debt

The outstanding principal of a $1.7 million note payable by NP, re-issued in January 2011 (the "Note Payable"), was fully amortized as of June 30, 2014. As of June 30, 2013, the minimum future principal maturities of the Note Payable, totaling $390 thousand, were considered a current liability.

The variable interest rate of the Note Payable is based upon the Wall Street Journal Prime Rate (the "Index") plus 1.00%, subject to a floor rate of 6.25%. As of June 30, 2013, the Index was 3.25%, resulting in an interest rate of 6.25% per annum. Under the Note Payable, NP is subject to certain customary financial and restrictive covenants. As of June 30, 2013, NP was in compliance with all financial and restrictive covenants.

As of June 30, 2013, the Note Payable and Line of Credit were collateralized by a first mortgage and an assignment of production from Poplar and were guaranteed by Magellan up to $6.0 million, not to exceed the amount of the principal owed. The carrying amount of the Note Payable approximates its fair value, due to its variable interest rate, which resets based on market rates.

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,	
	2014	2013
	(In thousands)	
Fiscal year opening balance	$6,879	$7,784
Liabilities assumed	7	3
Accretion expense	367	433
Sale of assets (1)	(4,457)	—
Revision to estimate (2)	—	(758)
Effect of exchange rate changes	77	(583)
Fiscal year closing balance	2,873	6,879

Less current asset retirement obligations	397	476
Long term asset retirement obligations	$2,476	$6,403

(1) Related to the sale of the Amadeus Basin assets

(2) The revision primarily resulted from a change in the expected timing of estimated abandonment cost for our oil and gas properties.

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, 2014, and 2013, 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, including cash and cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates fair value due to the short term maturity of these instruments. The recorded value of the Line of Credit and Note Payable (see Note 5), approximates fair value due to their variable rate structure.

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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, 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

	June 30, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Securities available-for-sale	$44	$—	$—	$44
Liabilities:				
Contingent consideration payable	$—	$—	$3,940	$3,940

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, consistent with 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 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.

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:

			June 30,	
Description	Valuation technique	Significant unobservable inputs	2014	2013
Contingent consideration payable	Discounted cash flow model	Discount rate	8.0%	8.0%
		First production payout	June 30, 2015	December 31, 2015
		Second production payout	NA	December 31, 2016

Revisions to the fair value estimate of the contingent consideration payable is 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) income. As of June 30, 2014, the downward revision were a result of the fact that a second production payout cannot be reasonably assumed on the basis of current production estimates corresponding to the estimated proved reserves of Poplar at June 30, 2014.

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

	June 30, 2014	2013
	(In thousands)	
Fiscal year beginning balance	$3,940	$4,072
Accretion expense	315	326
Revision to estimate	(2,403)	(458)
Fiscal year closing balance	$1,852	$3,940

Assets and liabilities measured on a nonrecurring basis

Due to the unobservable nature of the significant inputs required to measure these items at fair value, they are classified within Level 3. The Company also utilizes fair value to perform an annual impairment test on its oil and gas properties, or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Fair value is estimated using expected undiscounted 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 years ended June 30, 2014, or 2013, no events or circumstances were identified that would indicate that an impairment of our oil and gas properties has 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, 2014	2013
	(In thousands)	
United States	$4,262	$(9,449)
Australia	(11,563)	(3,333)
United Kingdom	(2,741)	(4,047)
Loss from continuing operations	$(10,042)	$(16,829)

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

	June 30, 2014	2013
	(In thousands)	
Tax provision computed per federal statutory rate	$(3,013)	$(5,048)
State taxes, net of federal benefit	549	(40)
Foreign rate differential	417	(60)
Non taxable Australian revenue	(3,144)	288
Goodwill write off	(58)	—
Decreases related to lapse of applicable statute of limitations	—	685
Change in valuation allowance	3,476	999
Taxable dividends from subsidiaries, net of foreign tax credits	3,586	(1,053)
Foreign tax credit adjustment	(761)	787
Capital loss adjustment	73	309
Impact of rate change	291	140
Foreign currency translation differential	(434)	2,912
Contingent consideration payable write off	(710)	(45)
Other items	(272)	126
Consolidated income tax expense (benefit)	$—	$—

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

	June 30, 2014	2013
	(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	$(1,267)
Effective tax rate for continuing operations	—%	—%

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

	June 30, 2014	2013
	(In thousands)	
Deferred tax liabilities:		
Land, buildings and equipment	$(4,030)	$(2,946)
Other items	(157)	(124)
Total deferred tax liabilities	(4,187)	(3,070)
Deferred tax assets:		
Asset retirement obligations	923	817
Net operating losses, capital losses, and foreign tax credit carry forwards	13,891	10,342
United Kingdom exploration costs and net operating losses	3,851	3,555
Investments	2,378	32
Stock option compensation	2,839	1,971
Australian capitalized legal costs	143	258
Other items	141	219
Total deferred tax asset	24,166	17,194
Valuation allowance	(19,979)	(14,124)
Net long term deferred tax asset	$—	$—

For the fiscal year ended June 30, 2014, the valuation allowance increased by $5.9 million, primarily due to additional book losses on continuing operations. Of the $5.9 million increase, $2.3 million was recorded to other comprehensive income and is related to the unrealized loss on Central shares.

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

The US gross deferred tax assets and liabilities as of June 30, 2014, and 2013, respectively, consist primarily of foreign tax credits, property, plant and equipment, and stock options. The Australian deferred tax assets and liabilities from continuing operations as of June 30, 2014 consist primarily of unrealized capital loss, and net operating loss carry forwards. As of June 30, 2013, the Australian deferred tax assets from continuing operations consisted primarily of legal expenses. The Australian capital loss and net operating losses are carried forward indefinitely. The UK deferred tax assets and liabilities as of June 30, 2014, and 2013, respectively, consist primarily of capital allowance carry forwards which are carried forward indefinitely.

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, 2014.

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As of June 30, 2014, 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	2011 - 2013
Colorado	2011 - 2013
Connecticut	2010
Maine	2011 - 2013
Montana	2010 - 2013
Australia	2010 - 2013
United Kingdom	2010 - 2013

At June 30, 2014, 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:

	State Net Operating Losses	Federal Foreign Tax Credit
	(In thousands)	
Expires:		
2017	$7	$310
2018	—	—
2019	—	1,411
2020	399	624
2021	176	1,443
2022	—	3,655
2023 and thereafter	—	2,716
Total	$582	$10,159

There are no uncertain tax positions that would meet the more-likely-than-not recognition threshold for the fiscal years ended June 30, 2014, or 2013.

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 employees, including officers, directors, and consultants of the Company (or subsidiaries of the Company) who are selected to receive incentive compensation awards by the Compensation, Nominating and Governance Committee (the "CNG Committee") of the Board of Directors of the Company (the "Board"), which is the plan administrator for the 2012 Stock Incentive Plan. The stated maximum number of shares of the Company's common stock authorized for awards under the 2012 Stock Incentive Plan is 5,000,000 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 288,435 as of January 15, 2013. The maximum aggregate annual number of common shares or options that may be granted to one participant is 1,000,000, 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 500,000. The maximum term of the 2012 Stock Incentive Plan is ten years.

Stock Option Grants

Under the 2012 Stock Incentive Plan, stock option grants may contain time based, performance based, or market based vesting provisions. During the fiscal year ended June 30, 2014, the Company granted a total of 3,000,000 stock options under the 2012 Stock Incentive Plan, of which 1,500,000 were granted as PBOs, and 1,500,000 were granted with market based

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vesting provisions. Performance metrics used to measure the potential vesting of the PBOs 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%). Potential vesting of the market based stock options are subject to the Company maintaining a $2.35 per share closing price for 10 consecutive trading days and median stock price of $2.35 over a period of 90 days. As of June 30, 2014, performance metrics (i), (iii) and (iv) were met.

As of June 30, 2014, 2,175,000 stock options with market based vesting provisions or PBOs had not vested, and 365,107 shares, including forfeited shares, were available for future issuance. During the fiscal year ended June 30, 2014, zero options were issued outside of the 2012 Stock Incentive Plan. Options outstanding have expiration dates ranging from November 28, 2015, through October 15, 2023.

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

	June 30, 2014 Number of Shares	WAEPS [(1)]	2013 Number of Shares	WAEPS [(1)]
Fiscal year beginning balance	7,888,957	$1.34	6,753,125	$1.44
Granted	3,000,000	$1.03	1,627,500	$1.23
Exercised	(275,000)	$1.07	—	$0.00
Forfeited [(2)]	(121,666)	$1.03	(491,668)	$1.23
Options outstanding at end of fiscal year	10,492,291	$1.26	7,888,957	$1.34
Weighted average remaining contractual term of outstanding options		6.0 years		5.9 years

(1) Weighted average exercise price per share.

(2) Fiscal year 2013 includes the effect of 100,000 historically granted stock options forfeited erroneously.

The total fair value of stock options vesting during the fiscal years ended June 30, 2014, and 2013, was $1.2 million, and $0.8 million, respectively. During the fiscal year ended June 30, 2014, 275,000 stock options were exercised for a number of 231,015 common stock shares, net of shares withheld to satisfy employee tax obligations. During the fiscal year ended June 30, 2013, zero stock options were exercised. Cash received from the exercise of stock options for the fiscal years ended June 30, 2014, and 2013, respectively, was $201 thousand, and zero. The following table summarizes options outstanding and exercisable as of June 30, 2014:

	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)]
$0.79 - $1.04	3,057,500	9.2 years	$1.02	827,500	9.1 years	$1.02
$1.05 - $1.11	1,415,000	8.0 years	$1.08	1,004,998	7.6 years	$1.09
$1.12 - $1.18	1,191,666	7.7 years	$1.13	624,999	7.2 years	$1.13
$1.19 - $1.40	3,100,000	1.9 years	$1.20	3,100,000	1.9 years	$1.20
$1.41 - $2.41	1,728,125	5.0 years	$2.03	1,728,125	5.0 years	$2.03
	10,492,291	6.0 years	$1.26	7,285,622	4.7 years	$1.36
Aggregate intrinsic value	$9,857,615			$6,152,424		

(1) Weighted average exercise price per share.

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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, 2014 PBOs [1]	Market Based [2]	2013 Time based and PBOs
Number of options	1,500,000	1,500,000	1,627,500
Weighted-average grant date fair value per share	$0.57	$0.69	$0.61
Expected dividend	$0.00	$0.00	$0.00
Forfeiture rate	0	0	0
Risk free interest rate	1.5 %-1.7%	2.8%	0.6 %-1.3%
Expected life (years)	0.4 -1.6	2.6	5.1 -6.0
Expected volatility (based on historical price)	61.7 %-61.9%	66.6%	60.3 %-63.5%

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

Stock Compensation Expense

The Company recorded $2.0 million and $0.8 million of stock compensation expense for the fiscal years ended June 30, 2014, and 2013, respectively. Stock based compensation is included under general and administrative expense in the consolidated statements of operations. At June 30, 2014, there was a total of $1.2 million in unrecognized stock compensation expense related to stock options granted. This cost is expected to be recognized over a weighted-average period of 1.7 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, 2015, it is expected that an additional 1,315,832 stock options will vest.

The Company's 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. Between July 1, 2013, and June 30, 2014, the Company issued a total of 266,664 shares of its common stock to non-employee directors pursuant to this policy.

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.

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.

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.
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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.

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- 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.
- 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

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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.

- 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, 2014, and 2013, respectively, the Company recorded preferred stock dividends of $1.7 million and $0.5 million, and accrued dividends in the amount of $429 thousand and $202 thousand related to the Series A Preferred Stock. 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,			
	2014		2013	
	Number of shares issued	Amount	Number of shares issued	Amount
	(In thousands, except share amounts)			
Fiscal year opening balance	19,239,734	$23,502	—	$—
Issuance of Series A Preferred Stock	—	—	19,239,734	23,502
PIK dividend shares issued, for previously accrued dividend	164,607	202	—	—
Current year PIK dividends shares issued	685,095	835	—	—
Fiscal year closing balance	20,089,436	$24,539	19,239,734	$23,502

Note 11 - Stockholders' Equity

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 149,539 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 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) 9,264,637 shares of the Company's Common Stock, (ii) a warrant granting Sopak the right to purchase from the Company an additional 4,347,826 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 9,264,637 shares of Common Stock, resulting in a value per share of $0.993 for the shares of Common Stock purchased. YEP, ECP, and Yamalco are entities affiliated with Nikolay V. Bogachev, a former director of the Company.

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,

	2014 Number of shares issued	Amount	2013 Number of shares issued	Amount
	(In thousands, except share amounts)			
Fiscal year opening balance	9,414,176	$9,333	—	$—
Repurchases through the stock repurchase program	—	—	149,539	137
Repurchase through the Collateral Agreement (1)	—	—	9,264,637	9,196
Net shares repurchased for employee tax costs upon vesting of restricted stock	10,938	11	—	—
Fiscal year closing balance	9,425,114	$9,344	9,414,176	$9,333

(1) Purchase price of $10.0 million reduced by the fair value of the warrant.

Retired Warrant

The Company formally retired the warrant purchased from Sopak 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 in the consolidated balance sheet.

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Assumptions used in estimating the fair value of the warrant included: (i) the Common Stock market price on the repurchase date of $0.90 per share; (ii) the warrant exercise price of $1.15 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%.

Note 12 - Earnings Per Share

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

	June 30,	
	2014	2013
	(In thousands, except share and per share amounts)	
Loss from continuing operations	$(10,042)	$(16,829)
Preferred stock dividend	(1,696)	(722)
Net loss from continuing operations, net of dividends attributable to preferred stock	(11,738)	(17,551)
Net income (loss) from discontinued operations	25,551	(2,938)
Net income (loss) attributable to common stockholders	$13,813	$(20,489)
Basic weighted-average shares outstanding	45,348,840	49,642,083
Add: dilutive effects of in-the-money stock options and non-vested restricted stock grants [1]	—	—
Diluted weighted-average common shares outstanding	45,348,840	49,642,083
Basic net (loss) earnings per common share:		
Net loss from continuing operations, net of dividends attributable to preferred stock [2]	$(0.26)	$(0.35)
Net income (loss) from discontinued operations	$0.56	$(0.06)
Net income (loss) attributable to common stockholders	$0.30	$(0.41)
Diluted net (loss) earnings per common share		
Net loss from continuing operations, net of dividends attributable to preferred stock [2]	$(0.26)	$(0.35)
Net income (loss) from discontinued operations	$0.56	$(0.06)
Net income (loss) attributable to common stockholders	$0.30	$(0.41)

(1) All diluted earnings per share calculations are dictated by the results from continuing operations, accordingly there was no dilutive effect on earnings per share in the periods presented.

(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 antidilutive. 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,	
	2014	2013
In-the-money stock options	6,335,622	75,000
Non-vested restricted stock	450,000	50,000
Total potentially dilutive securities	6,785,622	125,000

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 is primarily active 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, 2014	2013
	(In thousands)	
Revenue from NP oil production	$7,601	$6,131
Net income (loss) from continuing operations:		
NP [1]	$1,828	$(326)
MPA	(934)	(3,555)
MPUK	(2,585)	(4,726)
Corporate	(8,351)	(8,222)
Consolidated net losses from continuing operations	$(10,042)	$(16,829)
Assets:		
NP	$27,299	$26,093
MPA	14,073	32,735
MPUK [2]	4,486	2,021
Corporate	111,113	96,229
Inter-segment eliminations [3]	(75,536)	(74,806)
Consolidated assets	$81,435	$82,272
Expenditures for additions to long lived assets:		
NP	$20,334	$2,124
MPUK	526	350
Corporate	63	258
Consolidated expenditures for long lived assets	$20,923	$2,732

[1] The downward revision of the contingent consideration payable resulted in $2.1 million of other income associated with our NP segment, refer Note 7.
[2] Refer Note 20 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, 2014	2013
	(In thousands)	
Depletion, depreciation, amortization, and accretion:		
NP	$977	$988
Corporate	146	133
Consolidated depletion, depreciation, amortization, and accretion	$1,123	$1,121
Lease operating:		
NP	$6,257	$4,851
Exploration:		
NP	$541	$398
MPA	436	3,809
MPUK	2,507	3,700
Consolidated exploration	$3,484	$7,907

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, 2014:

	Total (In thousands)
Amounts payable in fiscal year:	
2015	$262
2016	268
2017	273
2018	90
Total	$893

Rental expenses for each of the years ended June 30, 2014, and 2013, were $0.6 million and, $0.6 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 Transaction"). 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 milestones 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 above for information regarding the estimated discounted fair value of the future contingent consideration payable related to the Nautilus Transaction.
Sopak Collateral Agreement. The Company has estimated that there is the potential for a statutory liability for required US Federal tax withholdings, and related penalties and interest, related to the Collateral Agreement as described in Note 11. As a result, we have recorded a total liability of approximately $1.6 million and $1.0 million as of June 30, 2014, and 2013, 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 $1.6 million and $1.0 million as of June 30, 2014, and 2013, respectively, under prepaid and other assets in the consolidated balance sheets.

Note 15 - Related Party Transactions
US Federal tax withholding. During the third quarter of fiscal year 2012, the Company identified a potential liability of approximately $2.0 million related to the Company's non-payment of required US Federal tax withholdings in the course of its initial acquisition of a part of NP. In October 2009, Magellan acquired 83.5% of the membership interests in NP (the "Poplar Acquisition") from the two majority owners of NP, White Bear LLC ("White Bear"), and YEP I, SICAV-FES ("YEP I"). Both of these entities are affiliated with Nikolay V. Bogachev, a foreign national who was a director of Magellan at the time of the Poplar Acquisition but has since resigned. Because YEP I was a foreign entity and the members of White Bear were foreign nationals, Magellan was required to make US Federal tax withholdings from the payments to or for the benefit of White Bear and YEP I. Of the $2.0 million liability, $1.3 million was estimated to relate to the interest sold by White Bear, $0.6 million to the interest sold by YEP I, and $0.1 million to Magellan's interest on the late payment of the US Federal tax withholdings.
With regards to White Bear, Mr. Bogachev filed his US income tax return and paid taxes due on the Poplar Acquisition, and Magellan has no further related potential liability. With regards to YEP I, which is now a defunct entity, Magellan concluded that it was unlikely that one of YEP I's successor entities would be filing the corresponding US income tax return. As a result, the Company initiated a disclosure process with the IRS. During October 2013, the Company received a letter from the IRS stating that the disclosure process was completed. The effect of this transaction on the consolidated statements of operations for the year ended June 30, 2013, resulted in other income of $0.4 million representing the difference between the original estimate and the estimated final liability of $0.1 million related to the YEP I withholding obligation. This transaction had no effect on the Company for the fiscal year ended June 30, 2014.
Key Energy Services. J. Robinson West, the Chairman of the Board of Directors of the Company, also serves as a non-employee director on the board of directors for Key Energy Services Inc. ("KES"). 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 year ended June 30, 2014, was $2.2 million. As of June 30, 2014, there were no unpaid contract fees related to KES.

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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 $161 thousand and $82 thousand of consulting fees related to Devizes for the fiscal years ended June 30, 2014, and 2013, respectively.

Note 16 - Employee Severance Costs

The Company is required to record charges for one-time employee severance benefits and other associated costs as incurred. 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. For the fiscal year ended June 30, 2013, the Company expensed total employee-related severance costs of $0.8 million to general and administrative expense in the consolidated statements of operations.

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.

The Company does not expect any additional benefits or other associated costs related to the terminations of employment as discussed above. The liability related to these severance costs, as of June 30, 2013, is included in the consolidated balance sheets under accrued and other liabilities. 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, 2014		2013
	Severance - Discontinued Operations	Severance - Termination Benefits	Severance - Termination Benefits
	(In thousands)		
Fiscal year beginning balance	$—	$418	$—
Charges to general and administrative expense	—	—	837
Charges to loss from discontinued operations, net of tax	1,210	—	—
Cash payments	(1,210)	(418)	(419)
Fiscal year closing balance	$—	$—	$418

Note 17 - Accumulated Other Comprehensive Income (Loss)

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

	June 30, 2014		
	Foreign currency translation	Unrealized investment holding loss	Total
	(In thousands)		
Fiscal year opening balance	$10,674	$(148)	$10,526
Changes in comprehensive income (loss):			
Other comprehensive income (loss) before reclassification	488	(7,256)	(6,768)
Amounts reclassified from other comprehensive loss [1]	(5,767)	—	(5,767)
Net current period other comprehensive loss	(5,279)	(7,256)	(12,535)
Fiscal year ended June 30, 2014	$5,395	$(7,404)	$(2,009)

[1] Reclassification of foreign currency translation gain to earnings upon the sale or substantially complete liquidation of an investment in a foreign entity. The reclassified gain is reported in the consolidated statement of operations under gain on disposal of discontinued operations, net of tax.

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Note 18 - Subsequent Events

Stock Based Compensation. Pursuant to the Company's compensation policy, a total of 96,330 shares of common stock were issued to non-employee directors on July 1, 2014.

On July 16, 2014 (effective August 15, 2014), C. Mark Brannum resigned as Vice President - General Counsel and Secretary of the Company. As a result Mr. Brannum forfeited 980,210 unvested stock options and 100,000 unvested shares of restricted stock.

Subsequent to the fiscal year ended June 30, 2014, 266,666 stock options were exercised resulting in the issuance of 203,360 shares of common stock, which number is net of shares withheld to satisfy certain employee tax and exercise price obligations.

Based on the activity related to our outstanding stock options and restricted stock after June 30, 2014, the Company had 819,323 shares, including forfeited shares, available for future issuance.

Line of Credit. On September 17, 2014, NP entered into a senior secured $8.0 million revolving line of credit note (the "LCN") with West Texas State Bank. The LCN will mature on September 30, 2015. The LCN is subject to quarterly floating interest payments based on the Prime Rate (currently approximately 3.25%) and a floor rate of 3.25%. The LCN 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. MPC provided a guarantee of the LCN secured by a pledge of its membership interest in NP. MPC and NP are subject to certain customary restrictive covenants under the terms of this loan.

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, 2014, and 2013, 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 year ended June 30, 2014, and by the Company's Operations Manager, Blaine Spies, for the fiscal year ended June 30, 2013. For both periods, the reserve estimates were audited by the Company's independent petroleum engineering firm, Allen & Crouch Petroleum Engineers ("A&C"). 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 future information becomes available.

	United States	Australia [1]	Total	
	Oil (Mbbls)	Gas (Bcf)	Oil (Mbbls)	Gas (Bcf)
Fiscal year ended June 30, 2012	8,905.2	11.5	8,905.2	11.5
Revision of previous estimates	(1,215.7)	0.2	(1,215.7)	0.2
Production	(320.9)	(0.3)	(320.9)	(0.3)
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	—
Proved Developed Reserves:				
Fiscal year ended June 30, 2013	1,581.5	11.4	1,581.5	11.4
Fiscal year ended June 30, 2014	2,494.6	—	2,494.6	—
Proved Undeveloped Reserves:				
Fiscal year ended June 30, 2013	5,787.1	—	5,787.1	—
Fiscal year ended June 30, 2014	3,241.1	—	3,241.1	—

[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 upward (downward) changes in previous estimates attributable to new information gained primarily from development activity, production history, and changes to the economic conditions present at the time of each estimate. During the year ended June 30, 2014, in the US, there was a 1,515 Mbbls downward revision of estimates related to the net removal from the reserves projections of seven PUD wells. During the fiscal year, we did not convert any proved undeveloped reserves to proved developed reserves. The proved undeveloped reserves as of June 30, 2013, which were related to the planned drilling of 16 wells, were originally identified and recorded in fiscal year 2010 in relation to a 20-well infill drilling program at Poplar. However, in light of the Company's increasing focus on CO_2-EOR and the fact that no wells for this drilling program have been drilled to date, the Company decided to change its plans such that those locations are currently not scheduled to be drilled within five years from the date of original booking, and to remove all of the related proved undeveloped reserves from its books as of June 30, 2014. During the fiscal year ended June 30, 2014, the Company added new proved undeveloped reserves amounting to 3,241 Mbbls and attributable to a new 9-well drilling program at Poplar. The nine well locations in this program are at Poplar in the immediate vicinity of the five wells that have been recently drilled for the CO_2-EOR pilot project. The Company plans to drill these wells as infill drilling locations for primary production from the Charles formation, with the additional benefit of potentially being converted for the purpose of CO_2-EOR development given their location as offsets to the pilot producer wells. The proved undeveloped reserves recorded with respect to these nine wells correspond only to primary production from the Charles Formation, although if CO_2-EOR has the desired impact, these wells may yield an additional tertiary component of production. During the fiscal year ended June 30, 2013, in the US, there was a 1,216 Mbbls downward revision of estimates related to the removal from the reserves projections of four PUD wells to be drilled during calendar year 2015. These wells were removed because the Company determined it would be beneficial to use only one as opposed to two drilling rigs for its PUD drilling program, and, as a result, it would not be feasible to drill these four wells within the projected time frame.

Divestitures of minerals in place. During the fiscal year ended June 30, 2014, in Australia, the Company sold its Palm Valley gas field to Central, resulting in an 11.4 Bcf adjustment and the elimination of all Australian reserves. There were no adjustments to reserves quantities relating to divestitures of minerals in place for the year ended June 30, 2013.

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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.

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,			
	2014		2013	
	United States	Australia	United States	Australia
Oil (per Bbl)	$86.11	NA	$82.90	NA
Gas (per Mcf)	NA	NA	NA	$4.92

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:

	United States	Australia	Total
	(In thousands)		
Fiscal year ended June 30, 2014			
Future cash inflows	$493,901	$—	$493,901
Future production costs	(226,464)	—	(226,464)
Future development costs	(23,594)	—	(23,594)
Future income tax expense	(73,820)	—	(73,820)
Future net cash flows	170,023	—	170,023
10% annual discount	(82,980)	—	(82,980)
Standardized measures of discounted future net cash flows	$87,043	$—	$87,043

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	United States (In thousands)	Australia	Total
Fiscal year ended June 30, 2013			
Future cash inflows	$610,853	$55,947	$666,800
Future production costs	(244,703)	(38,576)	(283,279)
Future development costs	(28,922)	(4,095)	(33,017)
Future income tax expense	(112,193)	—	(112,193)
Future net cash flows	225,035	13,276	238,311
10% annual discount	(127,644)	(2,991)	(130,635)
Standardized measures of discounted future net cash flows	$97,391	$10,285	$107,676

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

	United States (In thousands)	Australia	Total
Fiscal year ended June 30, 2012	$121,496	$8,579	$130,075
Net change in prices and production costs	(7,955)	(624)	(8,579)
Revisions of previous quantity estimates	(26,503)	192	(26,311)
Changes in estimated future development costs	3,473	5	3,478
Sales and transfers of oil and gas produced	(20,178)	556	(19,622)
Previously estimated development cost incurred during the period	3,419	7	3,426
Accretion of discount	19,269	1,016	20,285
Net change in income taxes	22,258	1,577	23,835
Net change in timing and other (1)	(17,888)	(1,023)	(18,911)
Fiscal year ended June 30, 2013	97,391	10,285	107,676
Net change in prices and production costs (2)	(10,222)	—	(10,222)
Revisions of previous quantity estimates (3)	(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

(1) For fiscal year 2013, in the US, there was a $17.9 million downward revision in reserves value due to changes in timing and other. This revision primarily relates to the change, relative to the prior year reserves projections, in the expected timing of drilling and completing PUD wells and the attendant cash flow expected from these wells. During fiscal year 2013, the Company focused its activities at Poplar on executing water shut-off treatments due to their potential attractive economics. As a result, PUDs previously estimated to be drilled during fiscal year 2013 were postponed, resulting in a change in the annual quantity and timing of PUD wells to be drilled in the current reserves projections.

(2) For fiscal year 2014, in the US there was a $10.2 million downward revision in reserves value due to the net change in prices and production costs. This change was the result of increased production cost estimates that more than offset impact of the increase in the assumed price per barrel of oil between fiscal year 2013 and 2014. The Company revised its estimated future production costs upwards following a detailed bottom-up analysis of historical and projected production costs undertaken during fiscal year 2014.

(3) This revision is related to our PUDs and is discussed in greater detail above under the heading "Analysis of Changes in Proved 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, 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
Fiscal year ended June 30, 2013				
Proved	$3,399	$—	$—	$3,399
Unproved	157	—	335	492
Exploration Costs	398	3,809	3,700	7,907
Development Costs	2,045	—	—	2,045
Total, including asset retirement obligation	$5,999	$3,809	$4,035	$13,843

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, 2014				
Fiscal year beginning balance	$497	$3,976	$1,762	$6,235
Additions to capitalized costs [1]	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	$19,956	$—	$1,890	$21,846
Fiscal year ended June 30, 2013				
Fiscal year beginning balance	$1,823	$4,388	$4,624	$10,835
Additions to capitalized costs	1,954	—	335	2,289
Reclassified to producing properties	(3,223)	—	—	(3,223)
Charged to expense	(57)	—	(3,035)	(3,092)
Exchange adjustment	—	(412)	(162)	(574)
Fiscal year closing balance	$497	$3,976	$1,762	$6,235

[1] The Company began implementing a CO_2-enhanced oil recovery pilot project at NP in the first quarter of fiscal year 2014.

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. During the third quarter of fiscal year 2013, the Company allowed a petroleum exploration and development license in the UK to expire at the end of its term. As a result, an impairment of $0.9 million was recorded in the consolidated statements of operations. Additionally, the Company recorded a write-down related to the Markwells Wood-1

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exploration well in the UK operated by Northern Petroleum. As a result, an exploration expense of $2.2 million was recorded in the consolidated statements of operations. No further write-downs were recorded during the fiscal year ended June 30, 2014.
At June 30, 2014, 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, 2014
	(In thousands, except per share data)				
Fiscal year ended June 30, 2014					
Revenue from oil production	$2,134	$1,632	$1,907	$1,928	$7,601
Total operating expenses	$6,591	$5,047	$4,311	$4,000	$19,949
Continuing operations:					
(Loss) income from continuing operations [1]	$(4,497)	$(3,437)	$(2,813)	$705	$(10,042)
Net (loss) income per basic common share outstanding	$(0.11)	$(0.09)	$(0.07)	$0.01	$(0.26)
Net (loss) income per diluted common share outstanding	$(0.11)	$(0.09)	$(0.07)	$0.01	$(0.26)
Attributable to common stockholders:					
Net (loss) income	$(5,250)	$(4,533)	$24,089	$(493)	$13,813
Net (loss) income per basic common share outstanding	$(0.12)	$(0.10)	$0.53	$(0.01)	$0.30
Net (loss) income per diluted common share outstanding	$(0.12)	$(0.10)	$0.53	$(0.01)	$0.30

[1] A downward revision of the contingent consideration payable during the fourth quarter of fiscal year 2014 resulted in $2.1 million of other income associated with our NP segment, refer Note 7.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	June 30, 2013
	(In thousands, except per share data)				
Fiscal year ended June 30, 2013					
Revenue from oil production	$1,460	$1,442	$1,706	$1,523	$6,131
Total operating expenses	$6,101	$7,319	$6,515	$4,479	$24,414
Continuing operations:					
Loss from continuing operations	$(4,405)	$(5,746)	$(3,726)	$(2,952)	$(16,829)
Net loss per basic common share outstanding	$(0.08)	$(0.11)	$(0.08)	$(0.08)	$(0.35)
Net loss per diluted common share outstanding	$(0.08)	$(0.11)	$(0.08)	$(0.08)	$(0.35)
Attributable to common stockholders:					
Net loss	$(5,310)	$(9,783)	$(4,332)	$(1,064)	$(20,489)
Net loss per basic common share outstanding	$(0.10)	$(0.18)	$(0.09)	$(0.04)	$(0.41)
Net loss per diluted common share outstanding	$(0.10)	$(0.18)	$(0.09)	$(0.04)	$(0.41)

During the third quarter of fiscal year 2014, pursuant to the Sale Deed, the Company completed the sale of Palm Valley and Dingo to Central PV (see Note 2). The transaction resulted in a gain on disposal of discontinued operations, net of tax in the amount of $30.0 million.

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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.

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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of June 30, 2014. 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, 2014.
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.

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CHANGE IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have not been any 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 Exchange Act) during the fourth fiscal quarter of the Company's fiscal year ended June 30, 2014, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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 headings "Item 1.01 Entry into a Material Definitive Agreement" and "Item 2.03 Creation of a Direct Financial Obligation or an Obligation under an Off-Balance Sheet Arrangement of a Registrant."

On September 17, 2014, NP entered into a senior secured $8.0 million revolving line of credit note (the "LCN") with West Texas State Bank. The LCN will mature on September 30, 2015. The LCN is subject to quarterly floating interest payments based on the Prime Rate (currently approximately 3.25%) and a floor rate of 3.25%. The LCN 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. MPC provided a guarantee of the LCN secured by a pledge of its membership interest in NP. MPC and NP are subject to certain customary restrictive covenants under the terms of this loan.

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PART III

Pursuant to General Instruction G(3), the information called for by Items 10, (except for information concerning the executive officers of the Company) 11, 12, 13, and 14 is hereby incorporated by reference to the Company's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from June 30, 2014. Certain information concerning the executive officers of the Company is included 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 September 18, 2014.

Name	Age	Office Held	Length of Service as Officer
J. Thomas Wilson	62	President and Chief Executive Officer	Since September 2011
Antoine J. Lafargue	40	VP - Chief Financial Officer and Treasurer	Since August 2010

For further information regarding the named executive officers, see the Company's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from June 30, 2014.

ITEM 11: EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from June 30, 2014.

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 provided in the Company's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from June 30, 2014.

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

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from June 30, 2014.

ITEM 14: PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided in the Company's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from June 30, 2014.

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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	Lease Purchase and Sale and Participation Agreement among Magellan Petroleum Corporation, Nautilus Poplar LLC, and VAALCO Energy (USA), Inc., dated as of September 6, 2011 (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q filed on November 14, 2011 and incorporated herein by reference)
2.2	Amendment dated December 11, 2012 to Lease Purchase and Sale and Participation Agreement among Magellan Petroleum Corporation, Nautilus Poplar LLC, and VAALCO Energy (USA) Inc. dated as of September 6, 2011 (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q filed on February 11, 2013 and incorporated herein by reference)
2.3	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)
2.4	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)
2.5	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)
2.6	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)

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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)
3.8	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+	Form of Indemnification Agreement between Magellan Petroleum Corporation and directors and officers pursuant to Article Sixteenth of the Restated Certificate of Incorporation and the By-Laws (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 2, 2009 and incorporated herein by reference)
10.2+	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)
10.3+	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)
10.4+	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)
10.5+	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)
10.6+	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	Registration Rights Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated July 9, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on July 14, 2009 and incorporated herein by reference)
10.12	First Amendment to Registration Rights Agreement among Magellan Petroleum Corporation, Young Energy Prize S.A., and YEP I, SICAV-FIS, dated as of October 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on October 19, 2009 and incorporated herein by reference)
10.13	Second Amendment to Registration Rights Agreement among Magellan Petroleum Corporation, Young Energy Prize S.A., and ECP Fund, SICAV-FIS, dated June 23, 2010 (filed as Exhibit 10(xx) to the registrant's Annual Report on Form 10-K for the fiscal year ended June 30, 2010 and incorporated herein

	by reference)
10.14+	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)
10.15+	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)
10.16+	Employment Agreement between Magellan Petroleum Corporation and J. Thomas Wilson dated November 2, 2011 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K/A filed on November 16, 2011 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 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)
10.19+	Indemnification Agreement between Magellan Petroleum Corporation and J. Thomas Wilson dated November 2, 2011 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K/A filed on November 16, 2011 and incorporated herein by reference)

10.20+	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)
10.21+	Restricted Stock Award Agreement between Magellan Petroleum Corporation and J. Thomas Wilson dated November 16, 2011 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K/A filed on November 16, 2011 and incorporated herein by reference)
10.22	First Amended and Restated Operating Agreement of Nautilus Poplar, LLC among Nautilus Technical Group, LLC, White Bear, LLC, YEP I, SICAV-FIS, and Eastern Rider, LLC dated as of October 14, 2009 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 19, 2009 and incorporated herein by reference)
10.23+	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)
10.24+	Form of Restricted Stock Award Agreement between Magellan Petroleum Corporation and non-employee directors, dated April 1, 2010 (Version A) (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q filed on May 14, 2010 and incorporated herein by reference)
10.25+	Form of Restricted Stock Award Agreement between Magellan Petroleum Corporation and non-employee directors, dated April 1, 2010 (Version B) (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q filed on May 14, 2010 and incorporated herein by reference)
10.26+	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)
10.27+	Indemnification Agreement between Magellan Petroleum Corporation and Antoine J. Lafargue, dated as of August 2, 2010 (filed as Exhibit 10.2 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 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)
10.29+	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)
10.30+	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)
10.31+	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)
10.32	Memorandum of Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated August 5, 2010 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on August 11, 2010 and incorporated herein by reference)
10.33	Investor Rights Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated August 5, 2010 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on August 11, 2010 and incorporated herein by reference)
10.34	Letter of Young Energy Prize S.A. to Magellan Petroleum Corporation dated January 13, 2011, effective as of December 23, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 18, 2011 and incorporated herein by reference)
10.35	First Amendment to Securities Purchase Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated February 11, 2011 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 18, 2011 and incorporated herein by reference)

10.36	Second Amendment to Securities Purchase Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated February 17, 2011 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on February 18, 2011 and incorporated herein by reference)
10.37	Investment Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated February 11, 2011 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 18, 2011 and incorporated herein by reference)
10.38	Amended Side Letter to Investment Agreement between Magellan Petroleum Corporation and Young Energy Prize S.A., dated February 17, 2011 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on February 18, 2011 and incorporated herein by reference)
10.39	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)
10.40	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)

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10.41+	Nonqualified Stock Option Award and Subscription Agreement between Magellan Petroleum Corporation and Milam Randolph Pharo dated November 30, 2011 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q filed on February 10, 2012 and incorporated herein by reference)
10.42+	Employment Agreement dated August 28, 2012 between Magellan Petroleum Corporation and C. Mark Brannum (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q/A filed on February 15, 2013 and incorporated herein by reference)
10.43+	Nonqualified Stock Option Award and Subscription Agreement dated August 28, 2012 between Magellan Petroleum Corporation and C. Mark Brannum (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q/A filed on February 15, 2013 and incorporated herein by reference)
10.44+	Restricted Stock Award and Subscription Agreement dated August 28, 2012 between Magellan Petroleum Corporation and C. Mark Brannum (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q/A filed on February 15, 2013 and incorporated herein by reference)
10.45+	Indemnification Agreement dated September 5, 2012 between Magellan Petroleum Corporation and C. Mark Brannum (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q/A filed on February 15, 2013 and incorporated herein by reference)
10.46+	Indemnification Agreement dated November 30, 2011 between Magellan Petroleum Corporation and Milam Randolph Pharo (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q/A filed on February 15, 2013 and incorporated herein by reference)
10.47+	Letter Agreement dated September 7, 2012 between Magellan Petroleum Corporation and Nikolay V. Bogachev (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q/A filed on February 15, 2013 and incorporated herein by reference)
10.48	Agreement for 2-D and 3-D Data Acquisition Services dated October 26, 2012 between Magellan Petroleum (Offshore) PTY LTD and Seabird Exploration FZ LLC (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q filed on November 9, 2012 and incorporated herein by reference)
10.49+	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)
10.50+	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)
10.51+	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)
10.52+	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)
10.53+	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)
10.54+	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)
10.55+	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 Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934)
10.56+	

	The 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)
10.57*	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.
10.58*	Promissory Note Agreement dated September 17, 2014 between Nautilus Poplar LLC as the Borrower and West Texas State Bank as the Lender.
10.59*	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.
10.60*	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.
14.1	Code of Conduct of Magellan Petroleum Corporation, as amended July 24, 2012 (filed as Exhibit 14.1 to the registrant's Annual Report on Form 10-K filed on September 24, 2012 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

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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)

By: /s/ J. Thomas Wilson
John Thomas Wilson, President and Chief Executive Officer
(as Principal Executive Officer)

By: /s/ Antoine J. Lafargue
Antoine J. Lafargue, Vice President - Chief Financial Officer and Treasurer
(as Principal Financial and Accounting Officer)

Date: September 18, 2014

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, and Director	Date: September 18, 2014
/s/ Antoine J. Lafargue Antoine J. Lafargue, Vice President - Chief Financial Officer, and Treasurer	Date: September 18, 2014
/s/ Vadim Gluzman Vadim Gluzman, Director	Date: September 18, 2014
/s/ Robert I. Israel Robert I. Israel, Director	Date: September 18, 2014
/s/ Brendan S. MacMillan Brendan S. MacMillan, Director	Date: September 18, 2014
/s/ Ronald P. Pettirossi Ronald P. Pettirossi, Director	Date: September 18, 2014
/s/ Milam Randolph Pharo Milam Randolph Pharo Director	Date: September 18, 2014
/s/ J. Robinson West J. Robinson West, Director	Date: September 18, 2014

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INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
10.57*	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.
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101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.
** Furnished herewith.