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	June 30, 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	June 30, 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 preclosing 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 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 14^{th} 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

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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	