MAGELLAN PETROLEUM CORP /DE/
Form 10-K/A
September 28, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K/A
(Amendment No. 1)
(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, 2012, or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
for the transition period from to
Commission file number 1-5507
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, CO	80203
(Address of principal executive offices)	(Zip Code)

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

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

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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 $0.968 closing price per share of the registrant's common stock as reported by the NASDAQ Capital Market, as of December 30, 2011 (the last business day of the most recently completed second fiscal quarter) was $41,241,284. 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.

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date:

Common stock, par value $0.01 per share, 53,885,594 shares outstanding as of September 17, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement related to the Annual Meeting of Stockholders for the fiscal year ended June 30, 2012, are incorporated by reference in Part III of this Form 10-K to the extent stated herein.

EXPLANATORY NOTE

This Amendment No. 1 to the Annual Report on Form 10-K (the "Amended 10-K") of Magellan Petroleum Corporation ("Magellan" or "our") amends our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, that was filed with the U.S. Securities and Exchange Commission (the "SEC") on September 24, 2012 (the "Original 10-K"). This Amended 10-K does not reflect a change in our consolidated results of operations, consolidated financial position, or consolidated cash flows as reported in the Original 10-K. This Amended 10-K is filed solely (i) to furnish the XBRL files with the "detailed tagging" data required to be included with this report, within the applicable grace period for furnishing such files; (ii) to correct a typographical error in the date of Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm and to change the description of the retrospective adjustments and the related financial statement footnote references to make them consistent throughout such report; and (iii) to correct the Foreign transaction (gain) loss amount appearing on page 20 under the Non-GAAP Financial Measures and Reconciliation section and on page 41 under the General and Administrative Expense section of Management's Discussion and Analysis of Financial Condition and Results of Operations, and to make a corresponding correction to the affected Adjusted EBITDAX amount for the fiscal year ended June 30, 2012, disclosed on pages 5, 20, and 32. No other changes were made to the Original 10-K.

This Amended 10-K does not reflect other events occurring after the filing of the Original 10-K, including exhibits, or modify or update those disclosures which may be affected by subsequent events. This Amended 10-K should be read in conjunction with Magellan's filings made with the SEC subsequent to the filing of the Original 10-K, as those filings may have been amended, as information in such reports and documents may update or supersede certain information contained in this Amended 10-K. Accordingly, this Amended 10-K only amends the items listed in the above paragraph, and no other information in the Original 10-K is amended hereby.

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PART 1

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

GENERAL

Magellan Petroleum Corporation (the "Company" or "Magellan" or "we" or "us") is an independent energy company engaged in the exploration, development, production, and sale of crude oil and natural gas. The Company conducts its operations through two wholly owned subsidiaries: Nautilus Poplar LLC ("NP"), which owns Poplar, a highly attractive oil field in the Williston Basin; and Magellan Petroleum Australia Limited ("MPAL"), a successful independent oil and gas company in existence since 1964 active in Australia and the United Kingdom.

Magellan was founded in 1957 and incorporated in Delaware in 1967. The Company's common stock has been trading on the NASDAQ since 1972, and trades 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 engineering, and management resources. We are committed to investing in these projects to establish their technical and economic viability. In turn, we will determine the most efficient way to create value and returns for our shareholders.

SIGNIFICANT DEVELOPMENTS IN FISCAL YEAR 2012

Fiscal year 2012 was a year of significant transition for Magellan. We made numerous changes to the structure and operations of our business that we believe have favorably impacted our future ability to generate value for our shareholders. During the year, we have strengthened our balance sheet with a significant cash position, gained full control and operatorship of our core assets, stabilized our operational and administrative platform, and initiated a number of cost saving measures. All of these actions will allow us to fund and execute our strategy to prove the value of our existing assets in an efficient manner.

Financial Performance

During the fiscal year, financial results were significantly negatively impacted by the planned termination of key revenue streams in Australia, namely the Palm Valley long term gas contract and the Amadeus Gas Trust. To address this sharp decline in performance, we have focused our efforts on replacing revenues and addressing our cost base. However, the effect of these initiatives has only marginally impacted the results of fiscal year 2012.

Revenues. For the fiscal year ended June 30, 2012, revenues totaled $13.7 million compared to $18.2 million in the prior year, a decrease of 25%. This decrease was primarily the result of the termination at Palm Valley of the 25-year gas sales contract with Northern Territory Power and Water Corporation ("PWC") (with the 25 year gas sales contract with PWC sometimes hereinafter referred to as the "PWC Contract") during January 2012, the termination of the Amadeus Gas Trust revenue stream during fiscal year 2011, and the sale of Magellan's interests in the Mereenie oil and gas field in May 2012. The termination of both the Amadeus Gas Trust revenue and the PWC Contract had been planned since 1983 and 2006, respectively.

During fiscal year 2012, our share of production at Poplar increased due to a combination of our workover program and the consolidation of our ownership in the leases of Poplar. Moreover, we have entered into a new gas sales contract at Palm Valley, which will ramp up to replace by 2015 the volumes previously sold under the PWC Contract at improved prices.

Net income and EPS. For the fiscal year ended June 30, 2012, net income totaled $26.5 million ($0.49/basic share), compared to a net loss of $32.4 million ($(0.62)/basic share) in the prior year. The increase in net income is primarily the result of closing the Santos SA transaction whereby Magellan sold its interests in Mereenie to Santos and Santos

sold its interests in the Palm Valley and Dingo fields to the Company, resulting in a gain on sale of assets of $36.2 million and the tax effect of recording the Company's Australian Petroleum Resource Rent Tax ("PRRT") which was enacted during the fiscal year 2012 and effective from July 1, 2012.
Adjusted EBITDAX. For the fiscal year ended June 30, 2012, Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) totaled negative $11.2 million, compared to negative

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$4.8 million in the prior year, a change of 135%. This decrease was the result of decreased revenues and increased lease operating expenses, offset by savings of $1.7 million in general and administrative expenses (excluding stock based compensation and foreign transaction loss).

Cash. As of June 30, 2012, Magellan had $41.2 million in cash and cash equivalents as compared to $20.4 million at the end of the prior fiscal year. The increase of $20.8 million was primarily driven by the completion of the Santos SA (see Santos asset swap transaction below), which generated $26.6 million in net cash proceeds for the Company. Our cash balance allows us to pursue our strategy of deploying capital resources towards assessing the potential value of our existing assets and determining the most efficient way to enhance shareholder value.

Rationalization of Asset Portfolio

During the fiscal year, Magellan executed a series of corporate transactions aimed at streamlining our corporate structure and gaining control and operatorship of our core assets.

Consolidation of ownership in Poplar. In the United States, we restructured and fully consolidated our ownership in Poplar (defined below) in September 2011, increasing the Company's economic exposure to the potential upside value of this asset while simplifying processes and procedures relating to accounting, reporting, and capital funding.

Santos asset swap transaction. On May 25, 2012, Magellan Petroleum (N.T.) Pty Ltd ("MPNT"), a wholly owned subsidiary of MPAL, and Santos QNT Pty Ltd and Santos Limited (collectively the "Santos Entities") completed a Sale Agreement (the "Santos SA"), and became the sole owner of the Palm Valley Interests and of the Dingo Interests, while Santos became the sole owner of the Mereenie Interests (see Note 2). As a result, we can now pursue a niche strategy of marketing Amadeus Basin gas to the mining industry in central Australia while reducing both field operating and overhead costs.

Initiation of Strategy to Prove-Up the Value of our Assets

During this past fiscal year, management articulated a strategy to focus on proving up the value of the Company's existing assets as the most economic way of increasing shareholder value. Towards that end, management has begun a number of initiatives to evaluate and determine the potential of the Company's oil and gas properties.

CO_2-EOR at Poplar. In the shallower formations at Poplar, which Magellan 100% owns and operates, management believes that the Charles formation is a potential candidate for a CO_2-enhanced oil recovery project ("CO_2-EOR"). Over the past year, we laid the groundwork for a CO_2-EOR pilot. After completing a detailed 3-D reservoir model earlier in the fiscal year, we commissioned laboratory analyses of oil samples from the Charles formation, the results of which confirm the potential viability of CO_2-EOR in that formation at Poplar. In addition, we have used the EPU 119 well to conduct CO_2 injectivity tests at reservoir conditions, the results of which tests were also favorable.

Other shallow formations of Poplar. Geological and geophysical analyses have led management to believe that there are other shallow formations at Poplar besides the Charles formation that contain significant hydrocarbon resources. In January 2012, Magellan identified a new pool discovery in the Amsden formation with the completion of the EPU 117 well, which has since produced commercial quantities of oil. Management is currently evaluating whether it is more economical to re-complete existing wells at Poplar in the Amsden formation or to drill new wells.

VAALCO farmout. In the United States, we farmed out the deeper intervals at Poplar to VAALCO Energy (USA), Inc. ("VAALCO") in September 2011. Under this arrangement, VAALCO will earn a 65% working interest in those intervals upon completion of three test wells aimed at evaluating the production potential of certain deep formations, in particular the Bakken/Three Forks formation. Magellan is carried 100% for the drilling and completion costs of these three wells and will be entitled to 35% of the gross revenue from the well less its proportionate share of lease burdens and taxes.

Improvements to Operating Assets

Poplar shallow intervals. Much of Poplar's current production is conventional production from the Charles formation generated by wells drilled in the 1950s and 1970s. These wells require significant workovers and maintenance to maintain stable production. Magellan implemented a workover program during the past fiscal year to assess the effectiveness of certain production-enhancing technologies, including stimoil treatments, acid stimulations, and water shut-off treatments. These assessments are ongoing, and have contributed to the increase in lease operating expenses during fiscal year 2012. If they are successful, these production enhancing technologies will be deployed on a broader scale and are expected to improve the production and profitability of the existing wells at Poplar.

Palm Valley. On May 25, 2012, MPNT and the Santos Entities completed the Santos SA, and MPNT became the sole owner of the Palm Valley Interests and of the Dingo Interests, while Santos became the sole owner of the Mereenie Interests, see Note 2. In the Amadeus basin in Australia, in connection with the Santos SA, Magellan executed a long-term sales agreement with Santos to sell substantially all of the remaining gas reserves from Palm Valley. Under this agreement, Magellan now sells gas from Palm Valley to Santos, who on-sells the gas to third party customers. As of June 30, 2012, there were two customers receiving gas from Palm Valley. Sales volumes from Palm Valley are expected to increase to approximately 1.5 Bcf per year by fiscal 2015 and are expected to be sold at prices significantly higher than those realized under the former long-term contract with PWC. Magellan also began to implement operational efficiencies at Palm Valley that have allowed for the reduction of field staff from ten to five workers while maintaining good oil and gas field practice.

Implementation of Recurring Cost Savings

During this fiscal year, Magellan reduced its general and administrative expenses (excluding stock based compensation and foreign transaction loss) by $1.7 million, or 12% . This reduction in expenses was primarily due to a $3.0 million reduction in third party consulting expenses, which resulted from reduced transaction expenses and the recruitment of additional staff that allowed us to internalize functions previously outsourced. This investment in human resources will leave the Company better prepared to handle the development of our projects in compliance with applicable laws and regulations. In addition, we have undertaken a number of cost saving initiatives, the positive impact of which in fiscal year 2012 was partially offset by implementation costs. These initiatives will have a greater impact in fiscal year 2013. Among our efforts to reduce costs, we consolidated our Portland, Maine, and Denver, Colorado, offices into a new single headquarters in Denver, Colorado, and we have streamlined our investor relations processes. Through fiscal year 2013, we will continue to implement cost savings initiatives to bring our cost structure more in line with our peers.

Overhaul of Financial and Administrative Functions

Over the past twelve months, management addressed a number of deficiencies and inefficiencies in the financial and administrative functions of the Company. With these issues now resolved, management believes we are better prepared for, and can be fully focused on, implementing our operational plans.

Remediation of material weakness. When the Company published its fiscal year 2011 Form 10-K, management concluded that the Company did not maintain effective internal controls over financial reporting, in particular in the area of the consolidated statement of cash flows and the review of third party expert work for significant, complex, and/or non-routine accounting issues. Management took this finding extremely seriously, and took significant measures to remediate these weaknesses. Management believes that remediating these weaknesses has now been accomplished.

Over the past year, we have also overhauled our accounting systems by bolstering our accounting staff, initiated the implementation of new accounting and land software, improving internal control processes, and reshaping the way we present our consolidated financial statements, to be more in line with industry practice. These efforts are essential to effectively running a business and establishing investor trust in our accounts.

Investor relations. In recent months, we have renewed our investor relations efforts to help the market better understand the intrinsic value of, and to attract a larger institutional following to, our stock. We have changed how we report our consolidated financial statements to be more in line with industry practice, launched a new website with detailed information about our assets, and created a new investor presentation which lays out our projects and milestones.

Relocation of headquarters. Recently we completed the relocation of the Company's headquarters from Portland, Maine, to Denver, Colorado. Consolidating our offices will achieve operational and organizational efficiencies. Basing our Company in an oil and gas hub will allow us to access talented professionals and service providers experienced in oil and gas and increase our exposure to new oil and gas opportunities. Management expects this move will prove critical to our success in growing this business.

OUTLOOK FOR FISCAL YEAR 2013

During fiscal year 2013, Magellan intends to execute on its strategy of proving the potential of its existing assets. We are particularly focused on the four projects below, which we intend to fund through a combination of the Company's cash resources and the risk capital invested by our farmout and joint venture partners.

- Implementing a pilot CO_2-EOR project at Poplar;
- Shooting and processing 3-D seismic over NT/P82, our exploration block offshore Australia; and
- Determining an exploration program for the unconventional formations in our United Kingdom leases.

- Evaluating the potential of, and possibly participating in the development of, the deeper formations at Poplar with our partner, VAALCO;

Management believes that each of these projects has significant potential that, if realized, will change the reserves and underlying value of our stock. Specific steps and milestones for each of these key areas are discussed below. By pursuing these courses of action, management expects that, by the end of fiscal year 2013, the Company will be able to validate and articulate clearly the value potential of its 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.

Pilot CO_2-EOR Project

In fiscal year 2013, the Company intends to evaluate the potential of CO_2-EOR in the Charles formation at Poplar by drilling a pilot CO_2-EOR, which consists of five-wells, including one CO_2 injector well and four producing wells. Magellan expects to incur up to $10.0 million in capital costs on these wells. Timing of the drilling of these wells will depend on the permitting process and drilling rig availability. The four producing wells are designed to yield both conventional oil production from the Charles formation and enhanced production as a result of the CO_2-EOR. As such, these four wells will constitute a portion of the wells to be drilled in the projections of our proved undeveloped reserves.

Poplar Deeper Formations

Under the terms of our agreement with VAALCO, VAALCO is required to spud and complete three test wells in the deeper formations at Poplar by December 31, 2012. The second test well, EPU 133-H, was completed as a horizontal well in the Bakken/Three Forks formation in September 2012. VAALCO has announced its intention to drill and complete the third test well as another horizontal well in the Bakken/Three Forks formation. The first test well, the EPU 120, was a vertical well drilled to a depth of 9,251 feet to test certain formations below the Bakken/Three Forks. Following VAALCO's determination that this well had not encountered hydrocarbons in commercial quantities, VAALCO announced its intention to recomplete this well as another horizontal Bakken/Three Forks well in fiscal year 2013. As a result of these three wells, we expect that by the end of fiscal year 2013 we will better understand the value potential of our approximately 22,000 net acres at Poplar.

Despite VAALCO's determination regarding the EPU 120 with respect to formations deeper than the Bakken/Three Forks, the Company believes the log data and core samples taken during the drilling phase of this well yielded encouraging results for the Nisku, Red River, and Winnipeg formations that justify further exploration of these formations in the future.

NT/P82, Offshore Australia

In the Bonaparte Basin, offshore Australia, the Company holds a 100% interest in the NT/P82 Exploration Permit. Magellan acquired this permit in May 2010, when it was engaged in pursuing the Evans Shoal transaction. 2-D seismic previously shot over the block shows a potential "bright spot" suggestive of a large gas resource estimated within a range of one to three Tcf. In accordance with the terms of the permit, which is due to expire in May 2016, the Company is planning to shoot 3-D seismic over the permit area, subject to environmental and permitting approvals, at a cost of less than $5.0 million, including the costs of processing and analyzing the seismic. The processing and analysis is expected to be complete by the end of fiscal year 2013, after which Magellan will have a much better understanding of the nature and size of the potential hydrocarbon resources in the permit area. If the results of the 3-D seismic are favorable, Magellan will then seek to design and implement an exploration and development plan for the block, most likely with a partner experienced in offshore drilling.

United Kingdom Exploration Plan

In fiscal year 2013, the Company intends to determine a definite course of action for exploring the unconventional formations underlying its licenses, most of which are due to expire by June 2015. Our primary focus in the United Kingdom is on establishing the potential value of the unconventional play underlying the licenses we co-own with Celtique Energie. Following our completion in fiscal year 2012 of 2-D seismic shot over these licenses, we have now fulfilled all our requirements except the drilling of a well. One potential strategy involves attracting an appropriate farmout partner to drill the wells required by these licenses.

With regard to the three licenses Magellan owns 100%, one of these is due to expire in September 2012 and is unlikely to be renewed, thereby reducing our gross and net acres in the United Kingdom to 361,762 and 192,622, respectively. Following the exploration work conducted with Celtique, management does not consider this license to be core to our strategy due to its location and assessed potential.

With respect to the Markwells Wood-1 well, operated by Northern Petroleum, following a long-term production test during fiscal year 2012, the well has been suspended and is currently being assessed by Northern for further actions.

OPERATIONS

Magellan operates in the single industry segment of oil and gas exploration and production. We have two reportable geographic segments, NP and MPAL, corresponding to our operations in the United States, and in Australia and the United Kingdom, respectively. NP's oil and gas assets consist of its interests in Poplar in the Williston Basin. MPAL's oil and gas assets consist of interests in the Palm Valley, Dingo, and Mereenie (prior to May 25, 2012) fields in the Amadeus Basin, onshore Australia; NT/P82, an exploration block in the Bonaparte Basin, offshore Australia; and various exploration licenses in the Weald and Wessex Basins, onshore United Kingdom. The locations of the Company's key oil and gas properties are presented

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in the map below. For certain additional information about the Company's reportable segments, see Note 9 to the financial statements included in Item 8: Financial Statements and Supplementary Data of this report.

Magellan's Areas of Operations

United States - Poplar

In the United States, 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, the "layer cake" structure of which provides multiple formations with hydrocarbon resource potential.

The field was discovered in the 1950s by Murphy Oil, who 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.

Poplar is composed of a 100% working interest in the oil and gas leases within the East Poplar Unit ("EPU") in Roosevelt County, Montana, and the working interests in various oil and gas leases that are adjacent to or near EPU ("Northwest Poplar" or "NWP") with the working interests varying between 63% and 100% in such leases (the Company's combined working interests in EPU and NWP are herein referred to as “Poplar”).

Our interests at Poplar include a 100% operated working interest in the interval from the surface to the top of the Bakken/Three Forks formation and a 35% non-operated working interest below that interval, which includes the Bakken/Three Forks formations.

Magellan 100% operated intervals. Magellan's current objectives are to prove up the potential of Poplar's various formations and to establish the viability of a CO_2-EOR project in the Charles formation, in which the substantial volume of oil in place offers Magellan a chance to significantly increase its oil reserves.

VAALCO 65% operated intervals. In September 2011, we farmed out part of our interest in the Bakken/Three Forks and deeper formations to VAALCO in return for their commitment to drill three exploration wells. This arrangement allows us to focus on the shallower formations while VAALCO tests the deeper formations, including the Bakken/Three Forks, Nisku, and Red River, on our collective behalf.

Australia - Amadeus Basin

In the Amadeus Basin, located near Alice Springs in central Australia, Magellan wholly owns 100% of the working interests in and operates two gas fields, Palm Valley and Dingo.

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Palm Valley. Palm Valley was discovered in 1965 and has been reliably selling natural gas since 1983. As of June 2012, the field has produced a cumulative total of 158 Bcf of gas. Through its direct connection to the Amadeus-Darwin Gas Pipeline, Palm Valley is able to meet the needs of its potential customers in Darwin, Northern Territory, and the mining operations adjacent to this pipeline. In 2012, Magellan entered into a new long-term gas sales contract with Santos whereby the Company has the ability to sell up to approximately 23 Bcf of natural gas, representing the majority of what the Company believes are the field's remaining gas reserves, over the next 17 years. To date Santos has future sale commitments for 11.5 Bcf of this gas. The firm sale commitments are a crucial part in determining the reserves that can be booked regarding this field.

Dingo. Dingo is a gas field discovered in 1981. Four appraisal wells drilled between 1981 and 1990 established the field's resource and production potential. Until recently, Australian gas market dynamics have prevented the full development of Dingo as a producing field and the construction of the 33-mile tie-in to the Amadeus-Darwin Gas Pipeline. Magellan maintains its interest in Dingo through Retention License No. 2, which expires in February 2014 but is subject to renewal for a further five years. No mandatory capital expenditure is required until new gas sales contracts are secured.

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. Under the terms of the permit, which is due to expire in May 2016, the Company is committed to shoot a minimum of 46 square miles of 3-D and 62 miles of 2-D seismic in 2012 and to drill a well by 2015.

United Kingdom

In the Weald and Wessex Basins, Magellan has interests in 11 Production Exploration and Development Licenses ("PEDLs"), representing a total of approximately 240,000 net acres onshore and offering both oil and gas prospects through conventional and unconventional development.

Magellan's acreage position is composed of three groups of PEDLs: (i) four licenses co-owned 50% with, and operated by, Celtique Energie, (ii) four licenses with varying ownership operated by Northern Petroleum, and (iii) three licenses wholly owned and operated by Magellan. To date in the United Kingdom, Magellan has participated in conventional wells, the most recent being the Markwells Wood-1, which was drilled and operated by Northern in PEDL 126. In addition, Magellan has contributed, along with its partners, to the exploration of its other licenses in accordance with the terms of each PEDL.

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, 2012.

	Oil (Mbbls)	Gas (MMcf)	Total (Mboe)[(1)]
Proved developed producing (PDP):			
United States	1,136	—	1,136
Australia	—	6,514	1,086
Total	1,136	6,514	2,222
Proved developed not producing (PDNP):			
United States	511	—	511
Australia	—	4,979	830
Total	511	4,979	1,341
Proved undeveloped (PUD):			
United States	7,258	—	7,258
Australia	—	—	—

Total	7,258	—	7,258
Total proved reserves	8,905	11,493	10,821

(1) Gas volumes are converted to Mboe at a rate of 6 MMcf of gas per Mbbl of oil based upon the approximate relative energy content of each fuel.

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	Oil (Mbbls)	Gas (MMcf)	Total (Mboe)[1]
PDP%	13 %	57 %	21 %
PDNP%	6 %	43 %	12 %
PUD%	81 %	— %	67 %
Probable:			
Developed	—	3,759	627
Undeveloped	4,097	10,065	5,775
Total	4,097	13,824	6,402
Total proved and probable reserves	13,002	25,317	17,223
Proved %	68 %	45 %	63 %
Probable %	32 %	55 %	37 %

(1) Gas volumes are converted to Mboe at a rate of 6 MMcf of gas per Mbbl of oil based upon the approximate relative energy content of each fuel.

As of June 30, 2012, our consolidated total proved reserves amounted to 10,821 Mboe, comprised of 8,905 Mbbls (68%) of proved oil reserves and 11,493 MMcf (45%) of proved gas reserves. All of our proved and probable oil reserves relate to our interest in Poplar, Montana. Of the 8,905 Mbbls of proved oil reserves, approximately 8,681 Mbbls (97%), 186 Mbbls (2%), and 38 Mbbls (1%) were derived from the Charles, Amsden, and Tyler formations, respectively.

As of June 30, 2012, all of our proved and probable gas reserves related to our interest in Palm Valley in Australia. Under the terms of the gas sales contract with Santos, we are entitled to sell up to approximately 22,500 MMcf of gas from Palm Valley to Santos, who on-sells the gas to third-party customers. As of June 30, 2012, proved gas reserves totaled 11,493 MMcf, corresponding to gas sales volumes committed to third-party customers under the Santos gas contract. The 13,824 MMcf of probable gas reserves correspond to the remaining volumes to be sold under the Santos gas contract plus additional volumes of gas estimated to be economically recoverable from Palm Valley.

Proved Undeveloped Reserves

As of June 30, 2012, we had 7,258 Mboe of proved undeveloped reserves, representing an increase of 317 Mboe, or 5%, over the prior year figure. This increase is the result of 1,247 Mboe added through Magellan's consolidation of its ownership in Poplar in September 2011, partially offset by a 721 Mboe reduction due to quantity revisions. During the fiscal year, we did not convert any proved undeveloped reserves to proved developed reserves.

As of June 30, 2012, we had no proved undeveloped reserves that had been on our books in excess of five years, and we recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well.

Probable Reserves

Estimates of probable developed and undeveloped reserves are inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate that is as likely as not to be achieved. Estimates of probable reserves are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

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

Internal Controls Over Reserve Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with regulations established by the U.S. Securities and Exchange Commission

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("SEC"). The Company relies upon a combination of internal technical staff and third party consulting arrangements for reserve estimation and review.

In the United States, the responsibility for reserves estimation is delegated to Blaine Spies, Magellan's Operations Manager since December 2011. Mr. Spies has over 19 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 region working for Halliburton. 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.

In Australia, reserve estimates were prepared by the Ryder Scott Company ("RS"), an independent petroleum engineering firm, in accordance with the Company's internal control procedures, which include the verification of input data used by RS, as well as management review and approval.

Third Party Reserve Audit

In the United States, reserve estimates were audited by Allen & Crouch Petroleum Engineers ("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. In addition, A&C served as the reserves auditor for Jonah Bank of Wyoming with respect to NP's loan currently outstanding with Jonah Bank of Wyoming.

In Australia, reserve estimates were prepared by RS, an independent petroleum engineering firm. A copy of the summary reserve report of RS is provided as Exhibit 99.2 to this Annual Report on Form 10-K. RS 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 13, to the consolidated financial statements of this Form 10-K.

VOLUMES AND REALIZED PRICES

The following table summarizes volumes and prices realized from the sale of oil and gas from properties in which we owned an interest during the periods stated. The table also summarizes operational costs per barrel of oil equivalent.

	Volumes			Average realized price (2)			Production
	Oil	Gas	Total	Oil	Gas	Total	costs (3)
	(Mbbls)	(MMcf)	(Mboe)(1)	(Per bbl)	(Per Mcf)	(Per boe)(1)	(Per boe)(1)
Fiscal year ended June 30, 2012							
United States	75	—	75	$82.66	$—	$82.66	$70.06
Australia	45	434	119	$137.21	$3.11	$64.40	$65.13
All other areas	2	—	2	*	$—	*	$—
Total	122	434	196	$101.64	$3.11	$70.95	$66.47
2011							
United States	68	—	68	$77.96	$—	$77.96	$43.85
Australia	55	712	174	$98.60	$2.26	$47.27	$36.10
Total	123	712	242	$96.11	$2.26	$56.27	$38.28
2010							
United States	42	—	42	$67.88	$—	$67.88	$36.44
Australia	68	3,430	640	$75.46	$4.47	$31.22	$12.83
All other areas	29	—	29	*	$—	*	$—
Total	139	3,430	711	$70.75	$4.47	$33.02	$13.67

(*) Not meaningful.
(1) Gas volumes are converted to Mboe at a rate of 6 MMcf of gas per Mbbl of oil based upon the approximate relative energy content of each fuel.

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(2) Prices per bbl or per Mcf are reported net of royalties. However, it should be noted that current period prices may be influenced by prior period royalty adjustments arising from annual royalty audits.
(3) Production cost excludes ad valorem and severance taxes.
Total production declined from 242 Mboe in fiscal year 2011 to 196 Mboe in fiscal year 2012, primarily as a result of the Palm Valley PWC contract termination in January 2012, which also contributed to the decline of gas production from 712 MMcf to 434 MMcf in fiscal year 2012. Production cost on a $/boe basis increased in Australia from $36.10/boe to $65.13/boe primarily due to decreased production, and increased in the United States from $43.85/boe to $70.06/boe primarily due to a material increase in workovers without a corresponding increase in production volumes. These factors combined to increase production costs from $38.28/boe to $66.47/boe in the United States and Australia.

PRODUCTIVE WELLS

Productive wells include producing wells and wells mechanically capable of production. In Australia, all gas wells were located at Palm Valley. The following table presents a summary of our productive wells by geography as of June 30, 2012.

	Oil Wells		Gas Wells		Total Wells	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
United States	39.0	37.4	—	—	39.0	37.4
Australia	—	—	1.0	1.0	1.0	1.0
Total	39.0	37.4	1.0	1.0	40.0	38.4

(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 years ended:

	June 30, 2012		2011		2010	
	Productive (2)	Dry (3)	Productive (2)	Dry (3)	Productive (2)	Dry (3)
Development wells, net (1):						
United States	4.0	1.0	1.0	—	—	—
Australia	—	—	—	—	0.4	—
Total	4.0	1.0	1.0	—	0.4	—
Exploratory wells, net (1):						
United States	1.0	—	—	—	—	—
Australia	—	—	—	—	—	0.9
Total	1.0	—	—	—	—	0.9
Total net wells	5.0	1.0	1.0	—	0.4	0.9

(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.

Out of the five productive wells completed during the current fiscal year, the EPU 117 was classified as an exploratory well, and the remaining four wells were comprised of four recompletions of existing wells at Poplar. The dry well was an unsuccessful recompletion of a well at Poplar.

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The following table summarizes the results, as of September 24, 2012, of our wells that were still in progress as of June 30, 2012.

	Still in Progress	
	Gross (1)	Net (2)
United States	1.0	1.0
All other areas	1.0	0.4
Total	2.0	1.4

(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.
The one well still in progress in the United States is the EPU 119, which is still being evaluated for CO_2 stimulation and possible conversion into an injection well.

ACREAGE
The following table summarizes gross and net developed and undeveloped acreage by geographic area at June 30, 2012.

	Developed (1)		Undeveloped (4)		Total	
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
United States						
Poplar	22,913	22,035	—	—	22,913	22,035
Australia						
Palm Valley	41,644	41,644	116,288	116,288	157,932	157,932
Dingo	—	—	116,139	116,139	116,139	116,139
NT/P82	—	—	1,566,647	1,566,647	1,566,647	1,566,647
All other areas						
United Kingdom	—	—	410,909	241,769	410,909	241,769
Total	64,557	63,679	2,209,983	2,040,843	2,274,540	2,104,522

(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 (78%) form a Federal Exploratory Unit which is held by production from any one well. Currently, Poplar contains 39 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 United States, 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.
Australia

In Australia, all of Magellan's onshore permits are issued by the Northern Territory and are subject to the Petroleum (Prospecting and Mining) Act and the Petroleum Act of the Northern Territory. Lessees have the exclusive right to produce petroleum from the land subject to payment of a rental and a royalty at the rate of 10% of the wellhead value of the petroleum

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produced. Rental payments may be offset against the royalty paid. The term of a petroleum lease is typically 21 years, and leases may be renewed for successive terms of 21 years each.

The below table summarizes the permits we maintain in Australia as of June 30, 2012.

Permit	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres [(1)]	Net acres [(2)]
Petroleum Lease No. 3 (Palm Valley)	Amadeus	11/7/2024	Magellan	100%	157,932	157,932
Retention License No. 2 (Dingo)	Amadeus	2/16/2014	Magellan	100%	116,139	116,139
NT/P82 (Timor Sea)	Bonaparte	5/12/2016	Magellan	100%	1,566,647	1,566,647
Total					1,840,718	1,840,718

[(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 in gross acres.

United Kingdom

In the United Kingdom, Petroleum Exploration and Development Licenses issued by the government are subject to the Petroleum Act. Licensees have the exclusive right to produce petroleum from the land subject to payment of a rental. 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 11 years if a well is drilled but no development program is approved by the Secretary of State for Energy and Climate Change.

The below table summarizes the permits we maintain in the United Kingdom as of June 30, 2012.

License	Geologic basin	Expiration date	Operator	Ownership interest	Gross acres [(1)]	Net acres [(2)]
PEDL 126	Weald	6/30/2014	Northern	40%	30,124	12,050
PEDL 135	Weald	9/30/2012	Magellan	100%	49,147	49,147
PEDL 137	Weald	9/30/2013	Magellan	100%	24,525	24,525
PEDL 155	Weald	9/30/2015	Northern	40%	13,029	5,212
PEDL 231	Weald	6/30/2014	Celtique	50%	98,880	49,440
PEDL 232	Weald	6/30/2014	Celtique	50%	23,342	11,671
PEDL 234	Weald	6/30/2014	Celtique	50%	74,100	37,050
PEDL 240	Wessex	6/30/2014	Northern	23%	1,778	409
PEDL 243	Weald	6/30/2014	Celtique	50%	74,100	37,050
PEDL 246	Weald	6/30/2014	Magellan	100%	10,769	10,769
PEDL 256	Weald	4/30/2015	Northern	40%	11,115	4,446
Total					410,909	241,769

[(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 in gross acres.

The PEDL 135 license, representing 49,147 gross and net acres, is due to expire in September 2012 and is unlikely to be renewed, thereby reducing our gross and net acres in the United Kingdom to 361,762 and 192,622 acres, respectively. Following the exploration work conducted with Celtique, management does not consider this license to be core to our strategy due to its location and assessed potential.

MARKETING ACTIVITIES AND CUSTOMERS

Customers

United States. In the United States, the Company has a sole customer who accounted for 45%, 30%, and 8% of the consolidated revenues during the fiscal years ended June 30, 2012, 2011, and 2010, respectively.

Australia. In Australia, revenue from one customer accounted for approximately 45%, 35% , and 25% of consolidated revenues for the years ended June 30, 2012, 2011, and 2010, respectively; revenue from another customer accounted for approximately 8%, 11%, and 10% of consolidated revenues in the same periods, respectively.

Delivery Commitments

Our production sales agreements contain customary terms and conditions with various parties that require us to deliver a fixed determinable quantity of product. During September 2011, Magellan entered into a Gas Supply and Purchase Agreement

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(the “Santos Gas Contract”) with the Santos Entities. The terms of the Santos Gas Contract commenced upon completion of the Santos SA and provide for the sale by Magellan to the Santos Entities of a total contract gas quantity of 25.65 Petajoules over the 17 year term of the Santos Gas Contract, subject to certain limitations regarding deliverability into the Amadeus Pipeline. We are not obliged to deliver fixed quantities of gas under the Santos Gas Contract other than that which we forecast for delivery over the ensuing 12 months. We can re-forecast quantities of gas every three months for the remainder of the contract year. If a shortfall in delivery of more than 10% occurs on any daily nomination by Santos, and confirmed for delivery by us, we incur a shortfall. If we shortfall on deliveries we can provide make-up gas in years 16 and 17 of the contract term. We will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for natural gas is projected, we have certain rights to arrange for third party gas to be delivered into the gathering lines and such volume will count towards our minimum commitment. We believe our production and reserves are adequate to meet these delivery commitments.

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 oil price during those times. Increased demand for heating and air conditioning can positively impact the price of natural gas during the winter and summer months, respectively. 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. In Australia, gas supply contracts are generally long term fixed price contracts and are unaffected by seasonality.

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, 2012, the Company had 35 total employees. We maintain approximately 6,000 square feet of functional office space in Denver, Colorado, for our executive and administrative headquarters and 4,435 square feet of office space in Brisbane, Australia.

GOVERNMENT REGULATIONS

Regulations Applicable to Foreign Operations

Many of the properties in which we have interests are located outside of the United States, and are subject to foreign laws, regulations, and related risks involved in the ownership, development, and operation of those 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. 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. As a result, an investment in us is subject to foreign regulatory risks in addition to those risks inherent in U.S. domestic oil and gas exploration and production company investments.

Our Australian operations 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 the acquisition of approvals before seismic acquisition or drilling commences, restrict the types, quantities, and concentration of substances that can be released into the

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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, 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.

Energy Regulations

Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for, and production of, oil and gas, including laws and regulations requiring permits for the drilling of wells; imposing bonding requirements in order to drill or operate wells; and governing the 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. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing 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, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and 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 can suspend or terminate our operations on federal or Indian leases.

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 and regulations may, among other things:

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

These laws, rules, and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be 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 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 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 and financial position.

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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 United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. 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.

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

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun 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 oil and 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, more intensive storms and flooding, and could adversely affect the demand for our products.

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 to 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 timely complete 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 (the "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.

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OSHA and other laws and regulation. 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 the 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 from tight formations. While we do not routinely utilize hydraulic fracturing techniques in our drilling and completion programs, that may change in the future if we embark on a successful Bakken/Three Forks play in Poplar. The 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. However, the EPA recently 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 which could adversely affect our financial position, results of operations, and cash flows. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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. 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 Petroleum Corporation. 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 (i) depletion, depreciation, amortization, and accretion expense, (ii) exploration expense, (iii) stock based compensation expense, (iv) foreign transaction loss (gain), (v) impairment expense, (vi) loss on Evans Shoal, (vii) gain on sale of assets, (viii) warrant expense, (ix) net interest income, (x) other income, (xi) income tax benefit (provision), and net (loss) income attributable to non-controlling interest in subsidiaries. Adjusted EBITDAX is not a measure of net income or cash flow as determined by accounting principles generally accepted in the United States ("GAAP"), and excludes certain items that we believe affect the comparability of operating results.

Our Adjusted EBITDAX measure provides additional information which 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

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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 items affecting the comparability of period to period operating results.

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

	June 30,		
	2012	2011	2010
	(In thousands)		
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)
Depletion, depreciation, amortization, and accretion expense	1,744	2,890	5,428
Exploration expense	6,291	2,854	1,273
Stock based compensation expense	1,560	1,670	2,305
Foreign transaction (gain) loss	(475)	951	677
Impairment expense	328	173	2,050
Loss on Evans Shoal	—	15,893	—
Gain on sale of assets	(40,413)	(969)	(6,817)
Warrant expense	—	—	4,276
Net interest income	(749)	(923)	(1,038)
Other income	(9)	—	(1,975)
Income tax (benefit) provision	(5,951)	5,141	2,646
Net (loss) income attributable to non-controlling interest in subsidiaries	(15)	(5)	(11)
Adjusted EBITDAX	$(11,191)	$(4,757)	$7,368

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 to differ from those 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 should not be considered to be indicative of future performance.

RISKS RELATING TO OUR BUSINESS

Our principal producing oil and gas properties in the Poplar and Palm Valley fields may stop producing oil and gas.

Our principal producing properties are located in the Poplar field in Montana and the Palm Valley field in Australia, and are subject to risks associated with regional supply and demand factors and potential delays or interruptions of production from wells in these areas resulting from governmental regulations, processing or transportation capacity constraints, and the availability of equipment, facilities, personnel, or services. Due to the relatively concentrated nature of our portfolio of producing properties, a number of our properties could experience any of the same conditions at the same time, resulting in relatively greater impact on our results of operations and cash flows than they might have on other companies that have a more diversified portfolio of properties. As a result of these risks, our producing properties may stop producing oil and gas, or there could be a material decrease in production levels at these fields. Since these properties are currently our principal revenue producing properties, any decline in production levels at these properties could have a material adverse effect on our revenues, results of operations, and cash flows. Any such adverse impact on our revenues and cash flows may restrict our ability to explore and develop oil and gas properties in the future and cause our stock price to decline.

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Our Palm Valley production revenues and cash flows depend on a long-term gas sales agreement.

In 2012, we entered into a long-term sales agreement with Santos to sell up to approximately 23 Bcf of natural gas from our properties in the Palm Valley field over the next 17 years to Santos, who on-sells the gas to third party customers. As of June 30, 2012, there were two customers receiving gas from Palm Valley. In the event this agreement becomes uneconomic or is unexpectedly breached or terminated or designated quantities are decreased as permitted under the contract terms, our revenues and cash flows could be adversely impacted, and our current niche strategy of marketing Amadeus Basin gas to the mining industry in central Australia may not be successful.

Our Poplar production revenues and cash flows depend on one purchaser, and the inability of the purchaser to meet its payment obligations to us may adversely affect our financial results.

Currently, we rely on an agreement with Plains Marketing, LP as the sole purchaser of our oil production at Poplar. If this purchaser reduces or discontinues its business with us, or if we are unable to successfully negotiate a replacement agreement with this purchaser, who can terminate services with a 90 day notice period, or if the replacement agreement is on less favorable terms, the effect on us could be 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 obligations to us, our revenues and cash flows from Poplar could be adversely affected.

Our CO_2-EOR project at Poplar may not be successful.

We believe that the Charles formation in the Poplar field is a potential candidate for a CO_2-EOR project, whereby CO_2 is injected into a reservoir to enhance oil recovery. While laboratory analyses and preliminary tests indicate that a CO_2-EOR project at Poplar is potentially viable, the additional production and reserves that may result from CO_2-EOR methods are inherently difficult to predict. If the CO_2-EOR project does not allow for the extraction of 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. If we are 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.

Our acquisitions of our 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, we typically perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests 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 could include our stock or require that we incur additional debt and contingent liabilities. As a result, future acquisitions 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, the recent economic and financial downturn has adversely affected 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 properties within the applicable lease 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 materially adverse effect on our ability to explore on or develop our properties.

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.

We may not be successful in sharing the exploration and development costs of the fields and permits in which we hold interests.

Our drilling plans depend, in certain cases, on our ability to enter into farm-in, joint venture, or other cost sharing arrangements with other oil and gas companies. If we are not able to secure such farm-in or other arrangements in a timely manner, or on terms which are economically attractive to the Company, 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 could be adversely affected and the market price of our common shares could decline.

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 continued 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 will depend, 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, such as adverse changes in currency values and foreign regulations relating to MPAL's exploration and development operations and to MPAL's payment of dividends to Magellan.

The properties in which we have interests located outside the United States are subject to certain risks related to the indirect ownership and development of foreign properties, including government expropriation and nationalization, adverse changes in currency values and foreign exchange controls, foreign taxes, U.S. taxes on the repatriation of funds to the United

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States, and other laws and regulations, any of which may have a material adverse effect on our properties, financial condition, results of operations, or cash flows. Although there are currently no exchange controls on the payment of dividends to Magellan by MPAL, such payments could be restricted by Australian foreign exchange controls, if implemented.

We have limited management and staff and will be dependent upon partnering arrangements.

We had 35 total employees as of June 30, 2012. 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 and stock price will be materially adversely affected.

Oil and 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 primarily upon the prices we receive for the oil and 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 prices of oil and natural gas have 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 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 Australian domestic oil and gas production and importation of such fuels and substitute fuels in 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;
- weather conditions, including effects of weather conditions on prices and supplies in worldwide energy markets;
- technological advances affecting energy consumption;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain crude oil prices and production controls;
- the competitive position of each such fuel as a source of energy as compared to other energy sources;
- strengthening and weakening of the United States dollar relative to other currencies; and
- the effect of governmental regulation 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. Furthermore, the ongoing worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A slowdown in economic activity caused by a recession would likely reduce worldwide demand for energy and result in lower oil and natural gas prices. Oil prices declined from previous years' record levels to below $70 per barrel in August 2009, and then have increased to $97 per barrel in August 2012, while natural gas prices have declined from over $13 per Mcf to approximately $3 per Mcf over the same period.

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. Gas sales contracts in Australia are adjusted to the gas price movements related to the Australian Consumer Price Index. Future gas sales not governed by existing contracts would generate lower revenue if natural gas prices in Australia were to decline. Sales of our proved oil reserves are dependent on world oil prices. The volatility of these prices will affect future oil revenues.

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

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration, and production, and face intense competition from both major and other independent oil and natural gas companies. Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, evaluate and select suitable properties, and consummate transactions in this highly competitive environment. In addition, we may not be able to compete with, or enter into cooperative relationships with, any such firms.

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

U.S. federal, state, tribal, and local authorities, and corresponding 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, oil and gas operations, and restoration. 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 grant 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.

The potential impacts of global warming and climate change may have an adverse effect on our operations and the demand for crude oil and natural gas.

Global warming and climate change have become the subject of an important public policy debate. Climate change remains a complex issue, with some scientific research suggesting that an increase in greenhouse gas emissions may contribute to the warming of the earth's atmosphere and other climatic changes and pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations.

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International agreements and national or regional legislation and regulatory measures to limit greenhouse gas emissions are currently in various stages of discussion or implementation. These and other greenhouse gas emissions-related laws, policies, and regulations may result in substantial capital, compliance, operating, and maintenance costs. For example, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the 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 cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation 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, some scientists have predicted that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operations or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies, or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses, or costs that may result from potential physical effects of climate change.

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 and the documents incorporated by reference in this report contain 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 most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and gas prices, 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. 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 cost 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.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows for financial statement disclosure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Reserves as of June 30, 2012, have been reported under SEC rules. The estimates provided in accordance with the SEC rules may change materially as a result of interpretive guidance that may be subsequently released by the SEC. We have included in this report estimates of our proved reserves at June 30, 2012, as prepared consistent with our independent reserve engineers' interpretations of the SEC rules relating to disclosures of estimated natural gas and oil reserves. These rules require SEC reporting companies to prepare their reserve estimates using reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. While the estimates of our proved reserves at June 30, 2012, included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could ultimately differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

We may be limited in our ability to book additional proved undeveloped reserves under the SEC rules.

Another impact of the SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program on our undeveloped properties.

We may not have funds sufficient to make the significant capital expenditures required to replace our reserves.

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, and/or equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to rely upon additional farm-in opportunities, debt or equity offerings, or other methods of financing to meet these cash flow requirements.

If we are not able to replace reserves, we may 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 development, exploration, 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 reserves at acceptable costs.

Future price declines may result in a write-down of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas operations. Under this method, the costs of successful wells, development dry holes, and productive leases are capitalized and amortized on a units-of-production basis over the life of the related reserves. Cost centers for amortization purposes are determined on a field-by-field basis. We record our proportionate share in joint venture operations in the respective classifications of assets, liabilities, and expenses. Unproved properties with significant acquisition costs are periodically, but at least annually, assessed for impairment in value with any required impairment charged to expense. The successful efforts method also imposes limitations on the carrying or book value of proved oil and gas properties. Oil and gas properties (including exploration rights), along with goodwill, are reviewed for impairment annually or whenever events or circumstances indicate that the carrying amounts may not be recoverable. In general, analyses are based on proved developed reserves, except in circumstances where it is probable that additional resources will be developed and contribute to cash flows in the future. For Palm Valley, future undiscounted cash flows were based upon the quantities of gas currently committed to the current contract and estimated sales subsequent to the contract. If such new contracts are effected, the proved developed reserves will be increased to the lesser of the current risk adjusted probable and possible reserves or the newly contracted quantities. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future write down of capitalized costs and a non-cash charge against future earnings.

Oil and gas drilling and producing 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 risks 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;

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- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties;
- suspension of operations;
- and compliance with, or changes in, environmental laws and regulations relating to air emissions, waste disposal and hydraulic fracturing, laws and regulations imposing conditions and restrictions on drilling and completion operations, and other laws and regulations, such as tax laws and regulations.

Our liability for environmental hazards includes those created either by the previous owners of properties that we purchase or lease 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. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Difficult conditions resulting from the ongoing U.S. and worldwide financial and credit crisis and significant concerns over the continuing recessions in the U.S. economy may materially adversely affect our business and results of operations, and we do not expect these conditions to improve in the near future.

Continual volatility and disruption since 2008 in worldwide capital and credit markets and further deteriorating conditions in the U.S. and Australian economies could affect our revenues and earnings negatively and could have a material adverse effect on our business, results of operations, and financial condition. 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.

Further, a number of our oil and gas properties are operated by third parties whom we depend upon 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 gas we produce. If current 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. This "trickle down" effect could significantly harm our business, financial condition, results of operations, and cash flows.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate all of the properties in which we own an ownership interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these non-operated properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements, or an operator's failure to act in ways that are in our best interests could reduce our production, revenues, and reserves. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including the operator's:

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

Currency exchange rate fluctuations may negatively affect our operating results.

The exchange rates among the Australian dollar and the U.S. dollar, as well as the exchange rates between the Australian dollar and the British pound, have changed in recent periods and may fluctuate substantially in the future. We expect that a majority of our revenue will be denominated in U.S. dollars in the future. However, at June 30, 2012, the U.S. dollar has strengthened against the Australian dollar which has had, and may continue to have, a negative impact on our revenues generated in the Australian dollar, as well as our operating income and net income, as considered on a consolidated basis. The foreign exchange gain for the year ended June 30, 2012, was $1.0 million and is included in accumulated other comprehensive income on the balance sheet. Any appreciation of the U.S. dollar against the Australian dollar is likely to have a positive impact on our revenue, operating income, and net income. Because of our U.K. development program, a portion of our expenses, including exploration costs and capital and operating expenditures, will continue to be denominated in British pounds. Accordingly, any material appreciation of the British pound against the Australian dollar could have a negative impact on our business, operating results, and financial condition.

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

The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws applicable to oil and natural gas exploration and production companies. These proposed changes include, but are not limited to:

- eliminating the immediate deduction for intangible drilling and development costs;
- eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development;
- repealing the percentage depletion allowance for oil and gas properties;
- extending the amortization period for certain geological and geophysical expenditures; and
- implementing certain international tax reforms.

These proposed changes in the U.S. 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.

RISKS RELATED TO OUR COMMON STOCK

Fluctuations in our operating results and other factors may depress our stock price.

During the past few years, the equity trading markets in the United States have experienced price volatility that has often been unrelated to the operating performance of particular companies. These fluctuations may adversely affect the trading price of our common shares. From time to time, there may be significant volatility in the market price of our common shares. Investors could sell shares of our common stock at or after the time that it becomes apparent that the expectations of the market may not be realized, resulting in a decrease in the market price of our common shares.

Our dividend policy could depress our stock price.

We have never declared or paid dividends on our common stock and have no current intention to change this policy. We plan to retain any future earnings to reduce our accumulated deficit and finance growth. As a result, our dividend policy could depress the market price for our common stock and cause investors to lose some or all of their investment.

We may issue a substantial number of shares of our common stock under our stock incentive plan, other equity grants, and our outstanding warrants, and shareholders may be adversely affected by the issuance of those shares.

As of June 30, 2012, there were 4,347,826 warrants outstanding and 6,753,125 stock options outstanding, of which 4,861,454 are fully vested and exercisable. As of that date, there were also 435,000 options available for future grants under our 1998 Stock Incentive Plan as amended in December of 2010. If all of these options and warrants, which total 11,100,951 in the aggregate, are awarded and exercised, shares received would represent approximately 21% of our outstanding common shares and would, upon their exercise and the payment of the exercise prices, dilute the interests of other shareholders and could adversely affect the market price of our common stock.

If our shares are delisted from trading on the NASDAQ Capital Market, their 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 Company's shares must maintain a minimum bid price of $1.00 as set forth in Marketplace Rule 5550(a)(2). If the bid price of the Company's shares trade below $1.00 for 30 consecutive trading days, then the bid price of the Company's shares must trade at $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule. On September 4, 2012, our shares closed at $1.17 per share, but our shares closed at below $1.00 on certain trading days in August 2012. If our shares were to be delisted from trading on the NASDAQ Capital Market, they may be eligible for trading on the OTCQB. The delisting of our shares from NASDAQ could adversely impact the liquidity and value of our shares.

Provisions in our charter documents and Delaware law may delay or prevent our acquisition by a third party.

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 beneficial to our existing stockholders. In addition, our certificate of incorporation and bylaws 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

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approval, with rights senior to those of 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 for their common stock.

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 THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

PRINCIPAL MARKET

The principal market for Magellan's common stock is the NASDAQ Capital Market. We trade under the symbol MPET. Our stock is also traded on the Australian Stock Exchange in the form of CHESS Depository Interests ("CDIs") under the symbol MGN. The below table presents the quarterly high and low prices on our most active market, NASDAQ, during the periods indicated. Each CHESS is matched by one Magellan common stock share. As of June 30, 2012, there were approximately 1,000,000 CDIs outstanding.

Quarter ended	High	Low
June 30, 2012	$1.39	$1.01
March 31, 2012	$1.49	$0.87
December 31, 2011	$1.24	$0.89
September 30, 2011	$1.89	$1.12
June 30, 2011	$2.58	$1.38
March 31, 2011	$3.45	$2.27
December 31, 2010	$3.03	$1.78
September 30, 2010	$1.97	$1.49

HOLDERS

As of September 7, 2012, the number of record holders of Magellan's common stock was 5,338; and, based upon inquiry, the number of beneficial owners was approximately 6,300, including approximately 1,100 who held beneficial ownership of shares through CHESS Depository Interests.

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 in the foreseeable future.

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning June 30, 2007, and ending on June 30, 2012, with the cumulative total returns of the NASDAQ Composite Index, a broad equity market index, and the Morningstar Oil and Gas E&P Industry Index, an industry group index. The graph assumes a $100 investment made on July 1, 2007, and the reinvestment of all dividends.

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RECENT SALES OF UNREGISTERED SECURITIES

Unregistered Inducement Grants during the fiscal year ended June 30, 2012, that were outside of the 1998 Stock Incentive Plan, as amended, were reported in Form 8-Ks.

ISSUER PURCHASES OF EQUITY SECURITIES

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program
April 1, 2012 - April 30 , 2012	—	$—	—	319,150
May 1, 2012 - May 31, 2012	—	$—	—	319,150
June 1, 2012 - June 30, 2012	—	$—	—	319,150
Total	—	$—	—	319,150

On December 8, 2008, the Company announced that its Board of Directors had approved a stock repurchase plan whereby the Company was authorized to purchase up to one million shares of its common stock in the open market. Through June 30, 2012, the Company had purchased 680,850 of its shares under this plan at an average price of $1.01 per share, or a total cost of approximately $0.7 million, all of which shares have been canceled. No shares were purchased during 2012, 2011, or 2010. On September 24, 2012, the Company announced that its Board of Directors had approved a new stock repurchase program whereby the Company is authorized to repurchase up to a total of $2.0 million in shares of its common stock. This authorization supersedes the prior plan and will expire on August 21, 2014. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including compliance with securities laws. Stock repurchases may be funded with existing cash balances or internal cash flow. The stock repurchase program may be suspended or discontinued at any time.

ITEM 6: SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data for Magellan for the fiscal years ended as indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with Part II, Item 7: Management's Discussion and Analysis of Financial

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Condition and Results of Operations of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this Form 10-K.

	June 30, 2012	2011	2010	2009	2008
	(In thousands, except per share amounts)				
Total revenues	$13,712	$18,176	$28,525	$28,191	$40,895
Net income (loss) attributable to Magellan Petroleum Corporation	$26,498	$(32,432)	$(1,446)	$665	$(8,892)
Net income (loss) per basic share outstanding	$0.49	$(0.62)	$(0.03)	$0.02	$(0.21)
Net income (loss) per diluted share outstanding	$0.49	$(0.62)	$(0.03)	$0.02	$(0.21)
Total assets	$92,574	$71,574	$90,706	$71,704	$85,295
Long-term debt	$390	$870	$232	$—	$—
Total equity attributable to Magellan Petroleum Corporation	$72,908	$52,528	$71,904	$53,513	$62,463
Non-controlling interest in subsidiaries	$—	$1,989	$1,914	$—	$—

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 Item 8: Financial Statements and Supplementary Data of this Form 10-K. In the following tables, the combination of Palm Valley and Mereenie represents our MPAL reporting segment. Amounts expressed in Australian currency are indicated as "AUD."

Forward looking statements are not guarantees of future performance, and our actual results may differ significantly from the results discussed in the forward looking statements. See "Forward Looking Statements" at the end of the section. Factors that might cause such differences include, but are not limited to, those discussed in the subsection entitled "Risk Factors" above, which are incorporated herein by reference. We assume no obligation to revise or update any forward looking statements for any reason, except as required by law.

OVERVIEW OF THE COMPANY

Magellan is an independent energy company engaged in the exploration, development, production, and sale of crude oil and natural gas. Our strategy is to enhance shareholder value by maximizing the value of our existing assets. We accomplish this through the exploration and development of our assets as outlined in Items 1 and 2: Business and Properties of this report.

SUMMARY RESULTS OF OPERATIONS FOR THE YEAR ENDED JUNE 30, 2012

For the year ended June 30, 2012, revenues totaled $13.7 million compared to $18.2 million in the prior year, a decrease of 25%. Operating income totaled $19.8 million compared to $28.2 million operating loss in the prior year. Net income totaled $26.5 million ($0.49/basic share), compared to a net loss of $32.4 million ($(0.62)/basic share) in the prior year. Adjusted EBITDAX (see Non-GAAP Financial Measures and Reconciliation under Part 1, Items 1 and 2: Business and Properties) totaled negative $11.2 million, compared to negative $4.8 million in the prior year, a change of 135%. For further detail, please refer to the discussion below in this section under Comparison of Financial Results and Trends Between Fiscal 2012 and 2011.

During the quarter ended December 31, 2011, we have changed the presentation of our financial statements to conform them to industry-specific norms and to improve our reporting to shareholders and stakeholders. Specifically, we have modified the presentation of expenses in the consolidated statements of operations and the presentation of property and equipment in the consolidated balance sheets. As a result, certain reclassifications have been made to the prior period financial statements to align them with this revised presentation format. These reclassifications have no impact on previously reported results.

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HIGHLIGHTS OF OPERATIONAL ACTIVITIES

During the fiscal year ended June 30, 2012, management articulated a strategy to focus on proving up the value of its existing assets as the most economic way of increasing shareholder value. Towards that end, management has begun a number of initiatives to evaluate and determine the potential of its oil and gas properties. The below discussion should be read in conjunction with the discussion of Significant Developments in Fiscal Year 2012 under Part1, Items 1 and 2: Business and Properties above and the section covering Comparison of Results and Trends between Fiscal Years 2012 and 2011 below.

Poplar (Montana, United States)

Magellan 100% operated intervals. During the year ended June 30, 2012, Magellan sold 75 Mbbls of oil attributable to its net revenue interests in Poplar, compared to 68 Mbbls of oil sold during the same period in 2011. These results represent a 10% increase in average daily sales for the year from 186 boepd to 205 boepd. Approximately 5 Mbbls out of the 7 Mbbls increase were attributable to sales from the EPU 117 well, which produces out of the Amsden formation, a new pool discovery made in January 2012. This well currently produces at a stabilized production rate of 10 to 20 bopd. The remaining production increase of 2 Mbbls is primarily the result of workovers and Magellan's consolidation of its ownership in Poplar in September 2011.

Poplar was discovered in the 1950s by Murphy Oil Company, with much of the field's development occurring in the Charles formation between the 1950s and 1970s. Most of the field's current production is conventional production from the Charles formation generated by wells initially drilled in that era, and these wells require significant workovers and maintenance to maintain stable production.

To improve the production and profitability of Poplar, Magellan implemented a workover and exploration program during the past fiscal year aimed at increasing conventional production from its operated formations. The Company tested and evaluated several unexplored shallow formations which are prospective for hydrocarbons. The discovery of the Amsden formation was a result of this effort, and management is currently evaluating whether it is more economic to develop this formation through the recompletion of existing wells or through the drilling of new ones. In addition, Magellan assessed the effectiveness of certain production-enhancing technologies, such as stimoil treatments, acid stimulations, and water shut-off treatments, in certain intervals. These assessments are ongoing, and, if successful, Magellan will seek to deploy them on a full-field basis.

During the fiscal year, Magellan also focused heavily on evaluating the potential for a CO_2-EOR project in the Charles formation at Poplar. During the third and fourth fiscal quarters, the Company commissioned various laboratory analyses of oil samples taken from the Charles formation, including studies of minimum miscibility pressure, CO_2 solubility swelling, and viscosity reduction. Magellan received analysis results back between May and August 2012, all of which confirm the potential viability of CO_2-EOR at Poplar. In addition, Magellan has utilized the EPU 119 well, initially drilled in 2010, to conduct CO_2 injectivity tests into the Charles formation under actual reservoir conditions. Such tests have been completed, and the results will support the viability of a CO_2-EOR at Poplar. Magellan is now working diligently to implement a five-well CO_2-EOR pilot project to be conducted during the fiscal year ending June 30, 2013.

VAALCO 65% operated intervals. In September 2011, we farmed out part of our interest in the Bakken/Three Forks and deeper formations to VAALCO in return for their commitment to drill three exploration wells. This arrangement allows us to focus on the shallower formations while VAALCO tests the deeper formations, including the Bakken/Three Forks, Nisku, and Red River, on our collective behalf.

Australia

Palm Valley. The Palm Valley gas field, which is operated by MPAL, produced a gross average of approximately 1.2 MMcf/d of natural gas for sale for the year ended June 30, 2012. Gas sales volumes at Palm Valley decreased due to the termination of the PWC Contract during January 2012. Gas sales resumed in February 2012 under month to month arrangements with Santos and were continued with Santos under a long-term gas sales agreement in May 2012 following completion of the Santos SA. Under these arrangements, sale terms were equivalent to those included in the Santos Gas Contract. The Santos Gas Contract became effective upon Completion of the Santos SA on May 25, 2012. To date, gas volumes sold under both the arrangements were significantly lower than under the PWC Contract, although volumes are expected to increase by fiscal year 2015 to levels similar to, and at prices significantly higher than, those realized under the PWC Contract. The average price of gas, net of royalties and prior year royalty adjustments, at Palm Valley was AUD $3.01/Mcf for the year ended June 30, 2012, compared to AUD $2.28/Mcf for the prior year.

During the fiscal year, Magellan took steps to reduce costs and improve operational efficiency at Palm Valley, including reducing its field staff from ten to five employees, while maintaining a safe and efficient operation, conducted in accordance with good oil field practice.

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Mereenie. The Mereenie oil and gas field, which is operated by Santos, produced a gross average of approximately 473 bbls of oil and condensate per day for sale during the period from July 1, 2011, to May 25, 2012, when the Santos SA was completed, compared to 493 bbls during the prior year. The average price of oil at Mereenie, net of royalties and prior year royalty adjustments, was AUD $132.92/bbl for the year ended June 30, 2012, compared to AUD $99.67/bbl for the prior year. There were no natural gas sales at Mereenie during fiscal years 2012 and 2011. Magellan sold its interests in Mereenie to Santos as part of the Santos SA (see Note 2) effective May 25, 2012, and the results of operations for fiscal year 2012 reflect a revenue contribution from Mereenie through that date.

United Kingdom

Celtique Energie Operated Licenses. In the Weald Basin, Magellan and Celtique Energie each own a 50% working interest in four licenses (PEDL 231, 232, 234, and 243) covering a gross total of approximately 270,000 acres, all expiring on June 30, 2014, unless extended. Celtique Energie continues to gather data to assess the prospect for unconventional and conventional hydrocarbon deposits in these licenses. In September 2011, Celtique completed the acquisition of approximately 200 km of 2-D seismic data. This seismic acquisition fulfilled our current work commitment under the licenses. These four licenses remain subject to contingent "drill-or-drop" requirements. This seismic data revealed several prospects, and an exploratory drilling program is under development.

Northern Petroleum Operated Licenses. In the Weald Basin of Southern England, the Company participated (40% interest) in the Markwells Wood-1 exploration well, which was drilled in PEDL 126 in December 2010. On November 21, 2011, this well was completed for production testing to establish pressures and flow rates in the existing wellbore. Further stimulation of the well was performed during December 2011 and February 2012, and production testing continued through April 2012 to establish a stabilized oil production rate. The well was then suspended, and is now being assessed by Northern for further actions. As operator of the well, Northern Petroleum will continue to publish periodic updates on the well status. Limited quantities of oil volumes have been produced from the Markwells Wood-1 well.

In January 2012, the United Kingdom Department of Energy, in the 26th Licensing Round, announced it will award an exploration license (an offshore license) to the Isle of Wight Joint Venture, which is composed of Northern Petroleum (63%), Magellan (23%), Egdon Resources (7%), Montrose Industries (5%), and Oil & Gas Investments (2%). The license is an exploration license for two part blocks located offshore in the Wessex Basin and contains a potential Wytch Farm type play. Northern Petroleum is the operator. Commitments to the license consist of a contingent “drill-or-drop” well with a decision on drilling to be made before the end of Permit Year 2.

ACQUISITIONS AND DIVESTITURES

During the fiscal year, Magellan executed a series of corporate transactions aimed at streamlining our corporate structure, gaining control and operatorship of our core assets, and allowing management to execute its strategy of proving the value of its assets.

Santos Transactions

On May 25, 2012, Magellan completed the Santos SA which consolidated our ownership in the Palm Valley and Dingo. The transaction had an effective date of July 1, 2011, and resulted in net cash proceeds of $26.6 million, including adjustments of $1.1 million (reflecting activity between the effective date and closing date), in addition to a gain on sale of assets in the amount of $36.2 million. The impact of this transaction is reflected in the consolidated financial statements included in this report (see Note 2).

Lease Purchase and Sale and Participation Agreement with VAALCO.

On September 6, 2011, the Company entered into a Lease Purchase and Sale and Participation Agreement with VAALCO, pursuant to which VAALCO will receive, subject to certain obligations, an undivided 65% of the Company's working interests at Poplar in formations including and below the Bakken/Three Forks. In exchange, Magellan received $5.0 million in cash proceeds and will be carried for 100% of the capital expenditures on the first three wells VAALCO will drill at Poplar in the deeper formations, all of which wells are due to be spud before December 31, 2012. The Company also recognized a gain on sale of assets in the amount of $4.0 million (see Note 2).

Acquisition of Non-Controlling Interest in Nautilus Poplar LLC and Acquisition of Additional Working Interests.

On September 2, 2011, effective from September 1, 2011, the Company entered into a Purchase and Sale Agreement (the "Nautilus PSA") between the Company and the non-controlling interest owners of its subsidiary, NP, (the "Nautilus Sellers"). The Nautilus PSA provided for the Company's purchase of all membership interests in NP and working interests in the leases of Poplar from the Nautilus Sellers in return for (i) $4.0 million in cash, (ii) $2.0 million less certain adjustments in privately issued shares of Magellan's common stock, and (iii) the potential for future production payments, collectively, of up to $5.0

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million if certain increased average daily production milestones are achieved. The impact of this transaction is reflected in the consolidated financial statements included in this report (see Note 2).

The Company and the Nautilus Sellers entered into a Registration Rights Agreement ("RRA"), pursuant to which the Company granted to the Nautilus Sellers certain registration rights with respect to the shares ("Registrable Securities") owned by each Nautilus Seller and issued under the Nautilus PSA. On October 14, 2011, the Company filed a registration statement on Form S-3 with the U.S. Securities Exchange Commission to register for public resale of 1,182,742 shares of the Company's common stock acquired in the Nautilus Restructuring by the Nautilus Sellers (the "Registration Statement"). On November 18, 2011, the Registration Statement on Form S-3 became effective. The Company agreed to pay all expenses associated with the registration of the Registrable Securities except the fees and disbursements of counsel to the Nautilus Sellers. The Company has no continuing obligation related to the RRA.

OTHER ITEMS

U.S. Federal Tax Withholdings

During the third quarter of fiscal year 2012, the Company identified a potential liability of approximately $2.0 million related to the Company's failure to make the required U.S. Federal tax withholding in the course of its initial acquisition of NP. In October 2009, Magellan acquired 83.5% of the membership interests in NP (the "Poplar Acquisition"), from the two majority owners of NP, White Bear LLC ("White Bear") and YEP I, SICAV-FES ("YEP I"). Both of these entities are affiliated with Mr. Bogachev, a Director of Magellan and a foreign national. Due to the status of YEP I as foreign entity and the members of White Bear being foreign nationals, Magellan was required to make U.S. Federal tax withholdings from the payments to or for the benefit of White Bear and YEP I. Of the $2.0 million liability, $1.3 million was estimated to relate to the interest sold by White Bear, $0.6 million to the interest sold by YEP I, and $0.1 million to Magellan's interest on late payment of the U.S. Federal tax withholdings.

Upon the filing of U.S. income tax returns in relation to the Poplar Acquisition and payment of corresponding income taxes by White Bear and YEP I, Magellan is deemed to be relieved of its liability for the U.S. Federal tax withholdings as well as related penalties and interest except for Magellan's interest on late payment of the U.S. Federal tax withholdings. With regards to White Bear, Magellan has confirmed that as of the date of this filing, Mr. Bogachev has filed his U.S. income tax return and paid taxes due on the Poplar Acquisition, which were estimated at $0.3 million. Magellan has agreed to pay Mr. Bogachev $0.3 million in additional compensation. Had Mr. Bogachev not filed and paid his tax return, Magellan's liability in relation to its U.S. Federal tax withholdings requirements was estimated at $1.3 million as of June 30, 2012. With regards to YEP I, Magellan continues to seek from YEP I or, because YEP I is a now defunct entity, from its successor entities, the filing of its U.S. income tax return.

As of June 30, 2012, we have recorded a total liability of $1.0 million under accrued and other liabilities in the consolidated balance sheets related to this matter. That amount is comprised of the $0.3 million payment to Mr. Bogachev, $0.6 million in withholdings, penalties, and interest related to YEP I, and $0.1 million related to Magellan's interest on late payment of the U.S. Federal tax withholdings. The effect on the consolidated statements of operations for the year ended June 30, 2012, is an expense of $0.9 million recorded under general and administrative expense and an interest expense of $0.1 million (see Note 11).

Based upon an evaluation of all relevant quantitative and qualitative factors, and after considering SEC Staff Accounting Bulletins Nos. 99 and 108, management believes that any amounts attributable to the years ending June 30, 2010, and 2011, and the impact of correcting such amounts in the year ending June 20, 2012, is not material to any of the Company's consolidated financial statements presented herein.

CONSOLIDATED LIQUIDITY AND CAPITAL RESOURCES

Historically, we have funded our activities from cash from operations and our existing cash balance. The Company has limited capital expenditure for which we are obligated pertaining to its leases and licenses, which allow for significant flexibility in the use of its capital resources. Based on its existing cash position including, the additional proceeds resulting from the completion of the Santos SA, and the various alternative sources of funds generally available to the Company, the Company believes it has sufficient financial resources to fund its ongoing operations and to finance projects that will further establish the full value of its assets.

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Uses of Funds

Capital Expenditures 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 production from any one well. Currently, Poplar contains 39 producing 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 by the results of ongoing engineering and technical analysis. In fiscal year 2013, the Company intends to evaluate the potential of CO_2-EOR in the Charles formation at Poplar by drilling a five-well pilot, including one CO_2 injector well and four producing wells. Magellan expects to incur up to $10.0 million in capital costs on these wells. Timing of the drilling of these wells will depend on the permitting process and drilling rig availability. The four producing wells are designed to yield conventional oil production from the Charles formation in addition to enhanced production as a result of the CO_2-EOR. As such, these four wells will constitute a portion of the wells to be drilled in the projections of our proved undeveloped reserves.

In the deeper intervals, which are operated by VAALCO and in which the Company has a 35% working interest, capital expenditures will be determined by the results of the three test wells which VAALCO is required to have spud by the end of calendar year 2012, and for which VAALCO will bear 100% of the capital expenditures. If these test wells are deemed successful, the Company plans to fund its 35% share of the cost of the future drilling program in the deeper formations of Poplar.

At Palm Valley, the Company’s interest in the field is governed by Petroleum Lease No. 3, which expires in November 2024 (and is subject to automatic renewal for another 21 years). The Company is not obligated to undertake significant mandatory capital expenditures in order to maintain its position in the lease. The Company’s discretionary capital expenditure plans are primarily focused on maintaining gas production from the existing facilities to meet the Santos Gas Contract demand while maintaining a safe and efficient operation, conducted in accordance with good oil field practice.

At Dingo, the Company’s interest in the field is governed by Retention License No. 2, which expires in February 2014 (and is subject to renewal for a further 5 years). No mandatory capital expenditure is required until new gas sales contracts are secured. Dingo contains two suspended wells which are capable of production. The Company is currently evaluating a number of options for the future development of this field and is in the process of identifying potential new gas customers.

In the Bonaparte Basin, offshore Australia, the Company holds a 100% interest in the NT/P82 Exploration Permit. Under the terms of the permit, which is due to expire in May 2016, the Company committed to a minimum 46 square mile 3-D seismic survey in 2012. Magellan currently plans to shoot 2-D and 3-D seismic over the permit in the second quarter of fiscal year 2013 at an estimated cost of less than $5.0 million, including the costs of processing and analyzing the seismic. Timing of the shoot is subject to finalization of our environment plans with local authorities and to the contract with the vessel and service provider.

In the United Kingdom, the Company’s interests are governed by various Petroleum Exploration and Development Licenses. The majority of these licenses expire in 2014, and all are subject to "drill-or-drop" obligations (for further detail, see Operations under Part 1, Items 1 and 2: Business and Properties). The Company has minimal remaining capital expenditure obligations with respect to its interest in the Markwells Wood-1 well operated by Northern Petroleum.

Contractual Obligations. The following table summarizes our obligations and commitments as of June 30, 2012, to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Purchase obligations (1)	$5,385	$5,385	$—	$—	$—
Asset retirement obligations	7,784	329	1,321	—	6,134
Contingent consideration payable (2)	4,072	—	4,072	—	—

Operating leases [3]	1,152	97	424	541	90
Long term debt, including interest [4]	918	517	401	—	—
Total	$19,311	$6,328	$6,218	$541	$6,224

[1] Purchase obligations are attributable to certain exploration and capital expenditures related to MPAL.
[2] Assumptions for the timing of these payments are based on our reserve report and planned drilling activity.
[3] Operating lease obligations are shown net of guaranteed sublease income.
[4] Long term debt in this table includes the current portion and accrued interest of $48 thousand for the 6.25% note payable (see Note 3).

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Sources of Funds

Cash and Cash Equivalents. On a consolidated basis, the Company had approximately $41.2 million of cash and cash equivalents at June 30, 2012, compared to $20.4 million as of June 30, 2011.

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. As of June 30, 2012, $39.7 million of the Company's consolidated cash and cash equivalents were deposited in accounts held by MPAL, of which $38.6 million was held in several Australian banks in time deposit accounts that have terms of 90 days or less. As of September 24, 2012, the company has repatriated $20.0 million of these Australian held funds to the U.S. The Company does not anticipate that U.S. Federal Income Tax will be owed on this amount. The intended use for the repatriated monies is the funding of Magellan's U.S. based operations, including part of its drilling activity at Poplar.

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 MPAL to the U.S., the Company is potentially liable for incremental U.S. Federal and State Income Tax, which may be reduced by the U.S. Federal and State net operating loss and foreign tax credit carry forwards available to the Company at that time.

Marketable Securities. The Company may from time to time invest in marketable securities consisting of investments in U.S. Treasury Bills with maturities usually not exceeding six months. As of June 30, 2012, and June 30, 2011, respectively, the Company had no marketable securities.

Existing Credit Facilities. The Company's outstanding borrowings are summarized below for the years ended:

	June 30,	
	2012	2011
	(In thousands)	
Outstanding borrowings:		
Term loan	$870	$1,422
Line of credit	50	1
Total	$920	$1,423

The Company, through its wholly owned subsidiary NP, maintains its only credit facility with Jonah Bank of Wyoming. As of June 30, 2012, the Company's borrowing capacity under these facilities totaled $2.3 million, consisting of a $1.3 million term loan and a $1.0 million line of credit. Of the $1.3 million term loan, $0.9 million was drawn as of June 30, 2012. Of the $1.0 million line of credit, $50 thousand was drawn, $25 thousand secured business credit cards used by NP, $25 thousand secured a line of credit in favor of the Bureau of Land Management, and $900 thousand remained available to borrow. As of June 30, 2012, NP was in compliance with its financial covenants as set forth in the term loan agreement. The credit facilities are collateralized by a first mortgage and an assignment of production from Poplar and are guaranteed by the Company up to $6.0 million but not to exceed the amount of the principal owed, which was $920 thousand as of June 30, 2012.

Other Sources of Financing. In addition to its cash and existing credit facilities, the Company has various alternatives to fund the development of its assets. These alternatives could potentially include entering into a corporate credit facility, a reserve-based loan facility, a farmout of a portion of the development program of some of the Company's assets, and an issuance of new shares to equity investors and monetization of non-core assets.

Cash Flows

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

	June 30,	
	2012	2011
	(In thousands)	
Cash (used in) provided by:		
Operating activities	$(10,441)	$(4,495)
Investing activities	35,629	(13,481)
Financing activities	(3,928)	561

Effect of exchange rate changes on cash and cash equivalents	(462)	4,240
Net increase (decrease) in cash and cash equivalents	$20,798	$(13,175)

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Cash used in operating activities during the year ended June 30, 2012, was $10.4 million, compared to cash used of $4.5 million in 2011. The increase in cash used in operating activities primarily resulted from a combination of a decrease in revenues of $4.5 million over the prior year and increased operational spending related to exploration and lease operating expenses of $3.7 million and $3.4 million, respectively. These factors were partially offset by a reduction in general and administrative costs (excluding stock based compensation and foreign transaction loss) of $1.7 million.

Cash provided by investing activities during the year ended June 30, 2012, was $35.6 million, compared to cash used of $13.5 million in 2011. The increase in cash provided by investing activities resulted from $5.0 million in proceeds from the VAALCO PSA (see Note 2), the refund of a $10.9 million deposit related to the Evans Shoal Asset Sales Deed, and $29.6 million in cash proceeds from the Santos SA (see Note 2), offset by $0.8 million spent on the purchase of non-controlling interests in Poplar and $9.6 million in expenditures on the development of our assets. Of the $9.6 million, $2.4 million related to the recompletion of four wells and the repair of one of our salt water disposal wells at Poplar, $1.6 million related to exploration activities at Poplar, primarily for the EPU 117 well, $1.2 million related to the Markwells Wood-1 well in the United Kingdom, and $3.4 million represented the acquisition of the remaining interest in the Palm Valley and Dingo gas fields.

Cash used in financing activities during the year ended June 30, 2012, was $3.9 million, compared to cash provided of $0.6 million in 2011. The increase in cash used in financing activities related to the $3.5 million purchase of the non-controlling interest in Poplar (see Note 2) and the repayment of the Company's long term debt of $0.5 million.

During the year ended June 30, 2012, the effect of changes in foreign currency exchange rates negatively impacted the translation of our AUD denominated cash and cash equivalent balances into U.S. dollars and resulted in a decrease of $0.5 million in cash and cash equivalents, compared to an increase of $4.2 million in 2011.

The Company also expects the impact of non-cash foreign transaction gains and losses in the consolidated statements of cash flows to be reduced in future periods. The source of the impact was primarily generated by MPAL's cash balances in U.S. dollar denominated accounts held in relation to the Evans Shoal Asset Sales Deed. Cash balances held in these accounts have now been reduced to immaterial amounts.

COMPARISON OF FINANCIAL RESULTS AND TRENDS BETWEEN FISCAL 2012 AND 2011

Oil and Gas Sales Volumes

The following table presents oil and gas sales volumes for the years ended:

	June 30,						
	2012	2011	Difference		Percent change		
Net sales by field:							
Poplar (Mbbls)	75	68	7		10		%
Palm Valley gas (MMcf)	434	712	(278	)	(39		)%
Mereenie oil (Mbbls)	45	55	(10	)	(18		)%
Total Australia sales (Mboe)	119	174	(55	)	(32		)%
Net sales by product:							
Oil (Mbbls)	122	123	(1	)	(1		)%
Gas (MMcf)	434	712	(278	)	(39		)%
Consolidated sales (Mboe)	194	242	(48	)	(20		)%
Consolidated sales (boepd)	531	662	(131	)	(20		)%

Sales volumes for the year ended June 30, 2012, totaled 194 Mboe (531 boepd), compared to 242 Mboe (662 boepd) sold in the prior year period, a decrease of 20%.The primary driver of this decline is the end of the PWC Contract of Palm Valley which was partially offset by increased production at Poplar. Sales volumes by product for the year ended June 30, 2012, were 63% oil and 37% gas, compared to 51% oil and 49% gas in the prior year, with the change due to the reduced contribution of gas sales from Palm Valley. At Poplar, volumes were positively impacted by the

EPU 117 well, which was completed in January 2012 in the Amsden formation, a new pool discovery at Poplar, by Magellan's consolidation of its interests in Poplar in September 2011 (see Note 2), and by the results of the continuing workover program. Gas sales volumes at Palm Valley decreased due to the termination of the 25 year PWC Contract during January 2012. Gas sales resumed in February 2012 under a month to month arrangement with Santos and were continued under a long-term gas sales agreement in May 2012 following

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completion of the Santos SA. The month to month arrangement was entered into with Santos while we were awaiting the Completion of the Santos SA and represented sales to Santos that were subsequently sold on by Santos to third-party customers. Since February 2012, gas volumes sold under these arrangements were significantly lower relative to the prior year period, although volumes are expected to increase over time and reach approximately 1.5 Bcf per year by fiscal 2015. At Mereenie, oil sales volumes decreased primarily due to Magellan's sale of its interests in the field in May 2012.

Oil and Gas Prices

The following table presents the average realized oil and gas prices for the years ended:

	June 30,			
	2012	2011	Difference	Percent change
Average realized price [1]:				
Poplar (USD/bbl)	$82.66	$77.96	$4.70	6 %
Palm Valley (AUD/Mcf)	$3.01	$2.28	$0.73	32 %
Mereenie oil (AUD/bbl)	$132.92	$99.67	$33.25	33 %
Consolidated (USD/boe)	$70.95	$56.27	$14.68	26 %

(1) Prices per bbl or per Mcf are reported net of royalties. Current period prices may be influenced by prior period royalty adjustments arising from annual royalty audits.

The average realized price for the year ended June 30, 2012, was $70.95/boe compared to $56.27/boe in the prior year period, an increase of 26%. This increase in price is primarily the result of an increase in the contribution of oil sales to total sales during the year ended June 30, 2012, as well as increased oil prices in the United States and Australia relative to the prior year. At present, the Company does not engage in any oil and gas hedging activities. Relative to the prior year period, the average realized price from oil sales at Poplar increased by 6% as a result of an increase in its benchmark pricing (WTI). The average realized gas price from Palm Valley increased by 32%, which reflects the higher gas prices realized under both monthly sales arrangements with Santos in place from February to May 2012 and the long-term gas sales contract in place with Santos from May 2012 compared to prices that were realized under the PWC Contract, which ended in January 2012. The gas price currently realized at Palm Valley is approximately AUD $4.7/Mcf, compared to AUD $2.3/Mcf under the terms of the prior long term gas sales contract. The average realized oil price from Mereenie increased by 33% as a result of an increase in its benchmark pricing (Tapis).

Revenues

The following table presents revenues for the years ended:

June 30,