EVOLUTION PETROLEUM CORP
Form 10-K
September 13, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended June 30, 2012

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 001-32942

EVOLUTION PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Nevada	**41-1781991**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

2500 CityWest Blvd., Suite 1300, Houston, Texas 77042

(Address of principal executive offices and zip code)

(713) 935-0122

(Registrant s telephone number, including area code)

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

Title of Each Class	**Name of Each Exchange On Which Registered**
Common Stock, $0.001 par value	NYSE MKT
8.5% Series A Cumulative Preferred Stock, $0.001 par value	NYSE MKT

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

None

(Title of Class)

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

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: o No: x

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: x No: o

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: x No: o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. x

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 definition of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o

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

The number of shares outstanding of the registrant s common stock, par value $0.001, as of September 11, 2012, was 28,840,163.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant s 2012 Annual Meeting of Stockholders to be filed within 120 days of the end of the fiscal year covered by this report are incorporated by reference into Part III of this report.

Table of Contents

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

2012 ANNUAL REPORT ON FORM 10-K

TABLE OF CONTENTS

Table of Contents

This Form 10-K and the information referenced herein contain forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words plan, expect, project, estimate, assume, believe, anticipate, intend, budget, forecast, predict and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in our Annual Report on Form 10-K as filed with the Securities and Exchange Commission. Furthermore, the assumptions that support our forward-looking statements are based upon information that is currently available and is subject to change. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages. All forward-looking statements attributable to Evolution Petroleum Corporation are expressly qualified in their entirety by this cautionary statement.

We use the terms, EPM, Company, we, us and our to refer to Evolution Petroleum Corporation.

GLOSSARY OF SELECTED PETROLEUM TERMS

The following abbreviations and definitions are terms commonly used in the crude oil and natural gas industry and throughout this form 10-K:

BBL. A standard measure of volume for crude oil and liquid petroleum products; one barrel equals 42 U.S. gallons.

BCF. Billion Cubic Feet of natural gas at standard temperature and pressure.

BOE. Barrels of oil equivalent. BOE is calculated by converting 6 MCF of natural gas to 1 BBL of oil.

BTU or British Thermal Unit. The standard unit of measure of energy equal to the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit. One Bbl of crude is typically 5.8 MMBTU, and one standard MCF is typically one MMBTU.

CO_2. Carbon dioxide, a gas that can be found in naturally occurring reservoirs, typically associated with ancient volcanoes, and also is a major byproduct from manufacturing and power production also utilized in enhanced oil recovery through injection into an oil reservoir.

Developed Reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

EOR. Enhanced Oil Recovery projects involve injection of heat, miscible or immiscible gas, or chemicals into oil reservoirs, typically following full primary and secondary waterflood recovery efforts, in order to gain incremental recovery of oil from the reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geologic structural feature and/or stratigraphic feature. *

Farmout. Sale or transfer of all or part of the operating rights from the working interest owner (the assignor or farm-out party), to an assignee (the farm-in party) who assumes all or some of the burden of development, in return for an interest in the property. The assignor may retain an overriding royalty or any other type of interest. For Federal tax purposes, a farm-out may be structured as a sale or lease, depending on the specific rights and carved out interests retained by the assignor.

Gross Acres or Gross Wells. The total acres or number of wells participated in, regardless of the amount of working interest owned.

Horizontal Drilling. Involves drilling horizontally out from a vertical well bore, thereby potentially increasing the area and reach of the well bore that is in contact with the reservoir.

Table of Contents

Hydraulic Fracturing. Involves pumping a fluid with or without particulates into a formation at high pressure, thereby creating fractures in the rock and leaving the particulates in the fractures to ensure that the fractures remain open, thereby potentially increasing the ability of the reservoir to produce oil or gas.

LOE. Means lease operating expense(s), a current period expense incurred to operate a well.

MBO. One thousand barrels of oil

MBOE. One thousand barrels of oil equivalent.

MCF. One thousand cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature. Standard pressure in the state of Louisiana is deemed to be 15.025 psi by regulation, but varies in other states.

MMBTU. One million British thermal units.

MMCF. One million cubic feet of natural gas at standard temperature and pressure.

Mineral Royalty Interest. A royalty interest that is retained by the owner of the minerals underlying a lease. See Royalty Interest .

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NGL. Natural gas liquids, being the combination of ethane, propane, butane and natural gasoline that can be removed from natural gas through processing, typically through refrigeration plants that utilize low temperatures, or through J-T plants that utilize compression, temperature reduction and expansion to a lower pressure.

NYMEX. New York Mercantile Exchange.

Operator. An oil and gas joint venture participant that manages the joint venture, pays venture costs and bills the venture s non-operators for their share of venture costs. The operator is also responsible to market all oil and gas production, except for those non-operators who take their production in-kind.

Overriding Royalty Interest or ORRI. A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of. See Royalty Interest .

Permeability. The measure of ease with which a fluid can move through a reservoir. The unit of measure is a darcy, or any metric derivation thereof, such as a millidarcy, where one darcy equals 1,000 millidarcys. Extremely low permeability of 10 millidarcys, or less, are often associated with source rocks, such as shale, making extraction of hydrocarbons more difficult, than say sandstone traps, where permeability can be one to two darcys or more.

Porosity. (of sand or sandstone). The relative volume of the pore space (or open area) compared to the total bulk volume of the reservoir, stated in percent. Higher porosity rocks provide more storage space for hydrocarbon accumulations than lower porosity rocks in a given cubic volume of reservoir.

Probable Developed Producing Reserves. Probable Reserves that are Developed and Producing. *

Probable Reserves. Additional reserves that are less certain to be recovered than Proved Reserves but which, together with Proved Reserves, are as likely as not to be recovered. *

Producing Reserves. Any category of reserves that have been developed and production has been initiated. *

Proved Developed Reserves. Proved Reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Table of Contents

Proved Developed Nonproducing Reserves (PDNP). Proved Reserves that have been developed and no material amount of capital expenditures are required to bring on production, but production has not yet been initiated due to timing, markets, or lack of third party completed connection to a gas sales pipeline. *

Proved Developed Producing Reserves (PDP). Proved Reserves that have been developed and production has been initiated. *

Proved Reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. *

Proved Undeveloped Reserves (PUD). Proved Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. *

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

PSI, or pounds per square inch, a measure of pressure. Pressure is typically measured as psig , or the pressure in excess of standard atmospheric pressure.

Present Value. When used with respect to oil and gas reserves, present value means the estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs to be incurred in developing and producing the proved reserves) computed using a discount factor and assuming continuation of existing economic conditions.

Productive Well. A well that is producing oil or gas or that is capable of production.

PV-10. Means the present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes. Unless otherwise noted, PV-10 is calculated using the pricing scheme as required by the Securities and Exchange Commission (SEC). PV-10 of proved reserves is calculated the same as the standardized measure of discounted future net cash flows, except that the standardized measure of discounted future net cash flows includes future estimated income taxes discounted at 10% per annum. See the definition of standardized measure of discounted future net cash flows.

Royalty or Royalty Interest. 1) The mineral owner s share of oil or gas production (typically between 1/8 and 1/4), free of costs, but subject to severance taxes unless the lessor is a government. In certain circumstances, the royalty owner bears a proportionate share of the costs of making the natural gas saleable, such as processing, compression and gathering. 2) When a royalty interest is coterminous with and carved out of an operating or working interest, it is an Overriding Royalty Interest, which also may generically be referred to as a Royalty.

Shut-in Well. A well that is not on production, but has not yet been plugged and abandoned. Wells may be shut-in in anticipation of future utility as a producing well, plugging and abandonment or other use.

Table of Contents

Standardized Measure. The standardized measure of discounted future net cash flows (the Standardized Measure) is an estimate of future net cash flows associated with proved reserves, discounted at 10% per annum. Future net cash flows is calculated by reducing future net revenues by estimated future income tax expenses and discounting at 10% per annum. The Standardized Measure and the PV-10 of proved reserves is calculated in the same exact fashion, except that the Standardized Measure includes future estimated income taxes discounted at 10% per annum. The Standardized Measure is in accordance with accounting standards generally accepted in the United States of America (GAAP).

SWIW. Salt water injection well.

Undeveloped Reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. *

Working Interest. The interest in the oil and gas in place which is burdened with the cost of development and operation of the property. Also called the operating interest.

Workover. A remedial operation on a completed well to restore, maintain or improve the well s production.

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* This definition may be an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X.

Item 1. Business

General

The terms we, us, our, our Company and EPM refer to Evolution Petroleum Corporation, a Nevada corporation formerly known as Natural G Systems, Inc. (Nevada, NGS), and, unless the context indicates otherwise, also includes our wholly-owned subsidiaries. Natural Gas Systems, Inc. (Delaware, Old NGS), a private Delaware corporation formed in September 2003 was subsequently merged into NGS.

Our petroleum operations began in September of 2003. We acquire known crude oil and natural gas resources and exploit them through the application of conventional and specialized technology, with the objective of increasing production, ultimate recoveries, or both.

Our team is broadly experienced in oil and gas operations, development, acquisitions and financing. We follow a strategy of outsourcing most of our property accounting, human resources, administrative and non-core functions.

Our principal executive offices are located at 2500 City West Blvd, Suite 1300, Houston, Texas 77042, and our telephone number is (713) 935-0122. We maintain a website at www.evolutionpetroleum.com, but information contained on our website does not constitute part of this document.

Our stock is traded on the NYSE MKT under the ticker symbol EPM . Prior to July 17, 2006, our stock was quoted on the OTC Bulletin Board under the symbol NGSY.OB . Prior to May 26, 2004, our stock was quoted on the OTC Bulletin Board under the symbol RLYI.OB .

At June 30, 2012, we had ten full-time employees, not including contract personnel and outsourced service providers.

Corporate History of Reverse Merger

Reality Interactive, Inc. (Reality), a Nevada corporation that previously traded on the OTC Bulletin Board under the symbol RLYI.OB and the predecessor of Evolution Petroleum Corporation, was incorporated on May 24, 1994, for the purpose of developing technology-based knowledge solutions for the industrial marketplace. On April 30, 1999, Reality ceased business operations, sold substantially all of its assets and terminated all of its employees. Subsequent to ceasing operations, Reality explored other potential business opportunities to acquire or merge with another entity while continuing to file reports with the Securities and Exchange Commission (SEC).

On May 26, 2004, Old NGS merged into a wholly owned subsidiary of Reality. Reality was thereafter renamed Natural Gas Systems, Inc. (NGS) and adopted a June 30 fiscal year end. As part of the merger, the officers and directors of Reality resigned, the officers and directors of Old NGS became the officers and directors of NGS, and the crude oil and natural gas business of Old NGS became that of NGS. Concurrently with the listing of NGS shares on the NYSE Amex (formerly the American Stock Exchange and

Table of Contents

now the NYSE MKT) during July 2006, NGS was renamed Evolution Petroleum Corporation to avoid confusion with similar names traded on the NYSE Amex and to better reflect our business model.

All regulatory filings and other historical information prior to May 26, 2004 that applied to Reality continue to apply to EPM after the merger.

Business Strategy

We are a petroleum company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas, onshore in the United States. We acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology to increase production, ultimate recoveries, or both.

We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain financial control of our assets for the benefit of our shareholders, including approximately 21% beneficially owned by all of our employees.

Our strategy is intended to generate scalable, low unit cost, development and re-development opportunities that minimize or eliminate exploration risks. These opportunities involve the application of modern technology, our own proprietary technology and our specific expertise in overlooked areas of the United States, where we may or may not choose to be the operator.

The assets we exploit currently fit into three types of project opportunities:

- Enhanced Oil Recovery (EOR),
- Bypassed Primary Resources, and
- Unconventional Development, especially utilizing our staff expertise in horizontal drilling.

Our active projects in these categories are:

Enhanced Oil Recovery

Delhi Field   Louisiana

Our mineral interests in the Delhi Holt Bryant Unit in the Delhi Field, located in Northeast Louisiana, are currently our most significant assets. The Unit has had a prolific production history totaling approximately 190 million barrels of oil through primary and secondary recovery operations since its discovery in the mid-1940s. At the time of our $2.8 million purchase in 2003, the Unit had minimal production.

The Unit is currently being redeveloped as an EOR project utilizing CO_2 flood technology following our farmout to a subsidiary of Denbury Resources, Inc. in 2006. Current estimates of gross proved and probable reserves by our independent reservoir engineer total 66 million barrels of additional recovery from the flooding operation, of which approximately 16.78 million barrels of oil are net to our interest.

We own two types of interests in the Unit:

- 7.4% of overriding and mineral royalty interests that are in effect throughout the life of the project, free of all operating and capital cost burdens.

- A 23.9% reversionary working interest with an associated 19.1% net revenue interest. The working interest reverts to us when the Operator has generated $200 million of net revenue from the 100% working interest less direct operating expenses and the cost of purchased CO_2. Upon reversion of the deemed payout, regardless of the Operator s actual capital expenditures, we begin bearing 23.9% of all future operating and capital expense and our net revenue interest increases from 7.4% to an aggregate 26.5%. Our current independent reserves report dated June 30, 2012 projects the deemed payout to occur on or about the end of calendar year 2013.

Our independent reservoir engineers, DeGolyer & MacNaughton (D&M), assigned the following net reserves to our interests at Delhi as of June 30, 2012:

- 11,011,570 BBLS of proved oil reserves, with a PV-10 of $409.1 million *

Table of Contents

- 5,780,906 BBLS of probable oil reserves, with a PV-10 of $102.8 million *
- 68% of proved volumes are developed.
- 46% of probable reserves are developed.

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* PV-10 of proved reserves is a non-GAAP measure, reconciled to the Standardized Measure at Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues under *Item 2. Properties* of this Form 10-K. Probable reserves are not recognized by GAAP, and therefore the PV-10 of probable reserves cannot be reconciled to a GAAP measure.

The Operator has planned up to six phases for the installation of the CO_2 flood. We refer to them as Phases I thru VI.

Phase I began CO_2 injection in November 2009. First oil production response occurred in March 2010, about three to four months earlier than expected. Implementation of Phase II, which is more than double the size of Phase I, commenced with incremental CO_2 injection at the end of December 2010. First oil production response from Phase II occurred during March 2011, three or more months ahead of expectations.

Phase III was installed during calendar 2011. The operator elected to expand Phase III twice during calendar 2011.

Phase IV was substantially installed during the first six months of calendar 2012.

We expect that the remaining phases will be installed similarly over the next few years. We further expect that four smaller reservoirs within the Unit and in similar formations and with similar production history will be developed in the future as an additional phase in the EOR project later this decade.

During fiscal 2012, Delhi s Louisiana Light Sweet (LLS) crude oil sales realized $111.29 per BBL average price, a 19% price premium over the $93.54 per BBL sales price we received from our Texas production. We expect that a positive market differential may continue into fiscal 2013.

Bypassed Primary Resource Projects

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying new conventional development and/or redevelopment projects targeting primary petroleum resources previously bypassed by industry in historically productive formations, generally due to inadequate technology or commodity prices. In selecting our candidates:

- We leverage our staff s extensive experience, gained over many years while employed at various large independent oil and gas companies in the pioneering of horizontal drilling practices;

- We seek projects that can effectively and efficiently redeploy projected net cash flows from Delhi Field farm-out and subsequent production;

- We seek projects that can generate multiple, scalable drilling opportunities with long term production growth; and

- We seek exposure to both crude oil and natural gas opportunities, with an emphasis on crude oil in recent years.

<u>Mississippi Lime</u> Kay County, North Central Oklahoma

In 2012, we entered into a joint venture with Orion Exploration, a private company based in Tulsa, OK. The joint venture is operated by Orion and engaged in the horizontal development of the Mississippian Lime reservoir in Kay County, Oklahoma within the rapidly growing play in north central Oklahoma and western Kansas. Our leasehold position is located in the eastern, oily side of the play. With the objective reservoir less than 4,000 feet in depth, the cost of drilling, fracturing and completing a horizontal well with 4,000 feet of lateral length is approximately $3 million. The joint venture has been gradually adding to the initial 11,700 net acre position. We hold a 45% share of the interest held by the joint venture. To date, we have drilled one gross salt water disposal well and reached total depth on our first two horizontally drilled wells in the Mississippian Lime formation, including lateral lengths of approximately 4,100 feet in the Sneath #24-1 and 4,800 feet in Hendrickson #1-1. Both wells are expected to be hydraulically fractured in September 2012.

Table of Contents

As of June 30, 2012, our independent reservoir engineer, Pinnacle Energy Services, assigned to us net probable reserves of 6,423,000 BOE with PV-10 of $69 million* associated with our net interest in 114 gross drilling locations.

Artificial Lift Technology (GARP)

Our artificial lift technology trademarked as GARP (Gas Assisted Rod Pump) was developed by one of our employees. Its design is intended to extend the life of horizontal wells with gas, oil or associated water production with the expectation of recovering an additional 10-30% of cumulative recovery at a cost less than $10 per BOE. Letters patent for our GARP technology were issued on August 30, 2011.

Prior to patent issuance, our GARP technology was tested on certain marginal producers we own and operate in the Giddings Field. The tests were successful in demonstrating that the process works; however, these candidates were unable to prove commercial application due to their low primary recoveries as producers.

Subsequent to receiving our patent, we entered into demonstration JV projects with two different industry operators during fiscal 2012 to prove commercial application. Based on our results, discussed more fully in our MD&A below, we are currently in discussions to expand GARP installations with both operators.

With continued success and industry acceptance, we believe GARP could be applicable to a large set of late stage horizontal producing wells worldwide.

Giddings Field Central Texas

We began leasing activities in the Giddings Field in December 2006 and currently hold 5,005 net developed acres and approximately 3,145 net acres as undeveloped and associated with our proved drilling locations as of June 30, 2012. In late calendar 2007, we initiated a redevelopment drilling program in the Giddings Field targeting the Austin Chalk and Georgetown formations. As of June 30, 2012, we have thirteen producing wells, eleven of which we drilled and two of which we restored to production through workovers. Three of the producing wells were drilled during fiscal 2011 as part of a joint venture to which we contributed the proved drilling locations. One of the three joint venture wells was deemed noncommercial due to water production in the target zone and was recompleted as a marginal producing well in another reservoir.

During Fiscal 2012, we also farmed out our Woodbine rights in approximately 900 net acres in exchange for cash and an ORRI of approximately 5%. Furthermore, on approximately 258 net acres of that total, we retained a 15% back-in working interest that reverts to us after a simple payout. We have not yet assigned any reserves to these interests, pending drilling results by the operator.

Total net proved reserves assigned to our properties in the Giddings Field by our independent reservoir engineer, W.D. Von Gonten & Associates, are 2,324 MBOE as of June 30, 2012. The total is a decrease of 399 MBOE from June 30, 2011 due to Giddings production during the year of 69 MBOE, negative revisions totaling 369 MBOE and additions of 40 MBOE. Our total investment of approximately $29 million to date has generated $13.4 million of cash flows from approximately 420 MBOE of total net production and proved PV-10 at June 30, 2012 of $35.6 million. See Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues under *Item 2. Properties* of this Form 10-K for a reconciliation of PV-10 to the Standardized Measure.

Lopez Field - South Texas

We acquired leases in the Lopez Field in South Texas with the intent of testing the concept of redeveloping old oil fields utilizing high flow rate production. If successful, we intended to expand the concept to similar fields in the area.

We currently own leases on approximately 891.6 net acres in the Lopez Field. As of June 30, 2012, our independent reservoir engineer, W.D. Von Gonten & Associates, recognized one proved producing well and six gross and net proved undeveloped well locations with 106 MBO of proved reserves. The engineer further assigned 475 MBO of probable reserves to 32 gross and net locations. During the year, we drilled two salt water injection wells and two oil producer wells. The first producer drilled exceeded our expectations with gross production averaging 16 BO per day for the quarter ended June 30, 2012. Based on the electric logs of the second oil producer and associated salt water injection well, we elected to swap well designations and applied for the necessary regulatory permits to convert the injection well to a producing well and the producing well to an injection well. As of yearend, those permits are still pending.

Table of Contents

Unconventional Resources

Woodford Shale Projects in Oklahoma   Southeast Oklahoma

Following the closing of our Delhi Farmout in June 2006, we identified two unconventional natural gas resource projects targeting the shallow Woodford Shale in Wagoner and Haskell counties of Oklahoma to balance the oily nature of our Delhi asset. These projects met our parameters of low drilling cost and risk, repeatable development and acceptable economics based on a $5 NYMEX natural gas price.

Due to persistent low natural gas prices and our perception that natural gas prices will likely remain below $5 over the near term, we discontinued our active development in these projects and intend to monetize our remaining leasehold.

Markets and Customers

We market our production to third parties in a manner consistent with industry practices.

In the U.S. market where we operate, crude oil and natural gas liquids are readily transportable and marketable. We do not currently market our share of crude oil production from Delhi. Although we have the right to take our current interests in-kind, we are currently accepting terms under the Delhi operator s agreement with Plains Marketing LP, for the delivery and pricing of our oil there.

Since March 2005 and into 2008, we sold all of our operated crude oil production to Plains Marketing LP, a crude oil purchaser, at competitive field prices. In January of 2008, we also began selling crude oil to Enterprise Crude Oil LLC, a crude oil gathering, transportation, storage and marketing company. Our agreements with both Plains Marketing LP and Enterprise Crude Oil LLC are under a normal (thirty day evergreen) sales contracts. During our fiscal 2010 year we amended our contracts to sell essentially all of our crude oil from our operated properties to Enterprise Crude Oil LLC. Oil production from our Lopez Field is sold to Flint Hill Resources. We believe that other crude oil purchasers are readily available.

We sell our natural gas and natural gas liquids from our properties in the Giddings Field, under the terms of normal evergreen sales contracts at competitive prices with DCP Midstream, LP, ETC Texas Pipeline, LTD., and Copano Field Services/Upper Gulf Coast, L.P. Gas sold to DCP and ETC is processed for removal of natural gas liquids, and we receive the proceeds from the sale of the NGL product less a fee and certain operating expenses. The price of natural gas sold to Copano is adjusted upward for the high BTU content. We have no other business relationships with our crude oil, natural gas or natural gas liquids purchasers.

The following table sets forth purchasers of our oil and natural gas production for the years indicated:

Customer	Year Ended June 30, 2012	2011	2010
Plains Marketing L.P. (includes Delhi production)	84%	60%	12%
Enterprise Crude Oil LLC	7%	15%	31%
ETC Texas Pipeline, LTD.	3%	12%	19%
DCP Midstream, LP	2%	6%	15%
Copano Field Services/Upper Gulf Coast, L.P.	3%	7%	23%
Flint Hills	1%	%	%

The loss of any single purchaser would not be expected to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive.

Market Conditions

Marketing of crude oil, natural gas, and natural gas liquids is influenced by many factors that are beyond our control, the exact effect of which is difficult to predict. These factors include changes in supply and demand, market prices, government regulation and actions of major foreign producers.

Over the past 25 years, crude oil price fluctuations have been extremely volatile, with crude oil prices varying from less than $10 to in excess of $140 per barrel. Worldwide factors such as geopolitical, macroeconomic, supply and demand, refining capacity, petrochemical production and derivatives trading, among others, influence prices for crude oil. Local factors also influence prices for crude oil and include increasing or decreasing production trends, quality differences, regulation and transportation issues unique to

Table of Contents

certain producing regions and reservoirs. In particular, the price we received for our Delhi oil substantially exceeded the price we received for our Texas oil production since the second half of fiscal 2011.

Also over the past 25 years, domestic natural gas prices have been extremely volatile, ranging from $1 to $15 per MMBTU. The spot market for natural gas, changes in supply and demand, derivatives trading, pipeline availability, BTU content of the natural gas and weather patterns, among others, cause natural gas prices to be subject to significant fluctuations. Due to the practical difficulties in transporting natural gas, local and regional factors tend to influence product prices more for natural gas than for crude oil.

Competition

The oil and natural gas industry is highly competitive for prospects, acreage and capital. Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than ours. Competitors are national, regional or local in scope and compete on the basis of financial resources, technical prowess or local knowledge. The principal competitive factors in our industry are expertise in given geographical and geological areas and the abilities to efficiently conduct operations, achieve technological advantages, identify and acquire economically producible reserves and obtain affordable capital.

Government Regulation

Numerous federal and state laws and regulations govern the oil and gas industry. These laws and regulations are often changed in response to changes in the political or economic environment. Compliance with this evolving regulatory burden is often difficult and costly, and substantial penalties may be incurred for noncompliance. To the best of our knowledge, we are in compliance with all laws and regulations applicable to our operations and we believe that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital cost of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements which are unpredictable. However, we do not currently anticipate that future compliance with existing laws and regulations will have a materially adverse effect on our consolidated financial position or results of operations.

See   Government regulation and liability for environmental matters that may adversely affect our business and results of operations   under *Item 1A. Risk Factors* of this Form 10-K, for additional information regarding government regulation.

Insurance

We maintain insurance on our properties and operations for risks and in amounts customary in the industry. Such insurance includes general liability, excess liability, control of well, operators extra expense, casualty, fraud and directors & officer s liability coverage. Not all losses are insured, and we retain certain risks of loss through deductibles, limits and self-retentions. We do not carry lost profits coverage and we do not have coverage for consequential damages.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at *www.evolutionpetroleum.com.* These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 2500 City West Blvd, Suite 1300, Houston, Texas 77042, or calling (713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC

Item 1A. Risk Factors

Risks relating to the Company

Operating results from oil and natural gas production may decline.

In the near term, our production is almost totally dependent on our working interests in the Giddings Field and our 7.4% royalty interests on early stage EOR production that began during March 2010 in the Delhi Field. The targeted reservoirs in the Giddings Field typically experience flush initial production, followed by steep harmonic decline rates that steadily flatten to much shallower decline rates. Although EOR production from proved reserves at Delhi has and is expected to grow over time, without further development activities in the Giddings Field, Delhi or our other properties, or without acquisitions of producing properties, our net production of oil and natural gas could decline significantly over time, which could have a material adverse effect on our financial condition.

The types of resources we focus on have substantial operational risks.

Our business plan focuses on the acquisition and development of known resources in partially depleted reservoirs, naturally fractured or low permeability reservoirs, or relatively shallow reservoirs. Shallower reservoirs usually have lower pressure, which translates into fewer natural gas volumes in place; low permeability reservoirs require more wells and substantial stimulation for development of commercial production; naturally fractured reservoirs require penetration of sufficient undepleted fractures to establish commercial production; and depleted reservoirs require successful application of newer technology to unlock incremental reserves.

Our CO_2-EOR project in the Delhi Field, operated by a subsidiary of Denbury Resources Inc., requires significant amounts of CO_2 reserves, development capital and technical expertise, the sources of which have been committed by the Operator. Although initial CO_2 injection began at Delhi in November 2009, initial oil production response began in March 2010 and a large part of the capital budget has already been expended, substantial capital remains to be invested to fully develop the EOR project and further increase production. The Operator s failure to manage these and other technical, strategic, financial and logistical risks may cause ultimate enhanced recoveries from the planned CO_2-EOR project to fall short of our expectations in volume and/or timing. Such occurrences would have a material adverse effect on the Company and its results of operations.

The existing well bores we are re-entering in the Giddings Field were originally drilled as far back as the 1980 s. As such, they contain older casing that could be more subject to failure, or the well files, if available, may be incomplete or incorrect. Such problems can result in the complete loss of a well or a much higher drilling and completion cost. Our proved undeveloped locations in the Giddings Field are direct offsets to current or previously producing wells, and there may be unusually long fractures that will connect our well to another producing or depleted well, thus reducing the potential recovery, increasing our drilling costs, or delaying production due to recovery of drilling fluid lost during drilling into the depleted fractures.

Our other projects in Oklahoma and Texas, although believed to have oil and/or gas resources, have yet to exhibit significant proved reserves. Therefore, their economic outcome is uncertain.

Our projects generally require that we acquire new leases in and around established fields or other known resources, and drill and complete wells, some of which may be horizontal, as well as negotiate the purchase of existing well bores and production equipment or install our proprietary artificial lift technology that has yet to be universally proven. Leases may not be available and required oil field services may not be obtainable on the desired schedule or at the expected costs. While the projected drilling results may be considered to be low to moderate in risk, there is no assurance as to what productive results may be obtained, if any.

Our limited operating history and limited production makes it difficult to predict future results and increases the risk of an investment in our company.

We commenced our crude oil and natural gas operations in late 2003 and have a limited operating history, particularly in our currently producing fields. All of our current production is the result of recent operational activities, thus our future production retains substantial variability. Therefore, we face all the risks common to companies in their early stage of development, including uncertainty of funding sources, high initial expenditure levels and uncertain revenue streams, an unproven business model, and difficulties in managing growth. Our prospects must be considered in light of the risks, expenses, delays and difficulties frequently encountered in establishing a new business. Any forward-looking statements in this report do not reflect any possible effects on us from the outcome of these types of uncertainty. Other than the significant gain we realized from the Delhi Farmout in fiscal 2006, we incurred significant losses from the inception of our oil and natural gas operations until we established profitability during the quarter ended March 31, 2011. Although we have been profitable since then, we cannot assure future profitability or success. While members of our management team have previously carried out or been involved with acquisition and production activities in the crude oil and natural gas industry while employed by us and other companies, we cannot assure you that our intended acquisition targets and development plans will lead to the successful development of crude oil and natural gas production or additional revenue.

The loss of a large single purchaser of our oil and natural gas could reduce the competition of our production.

For the year ended June 30, 2012, seven purchasers each accounted for all of our oil and natural gas revenues. The loss of a large single purchaser for our oil and natural gas production could negatively impact the prices we receive.

Table of Contents

We may be unable to continue licensing from third parties the technologies that we use in our business operations.

As is customary in the crude oil and natural gas industry, we utilize a variety of widely available technologies in the crude oil and natural gas development and drilling process. We do not have any patents or copyrights for the technology we currently utilize, except for the trademark and issued patent on our GARP artificial lift technology that has yet to reach commercial development. We generally license or purchase services from the holders of such technology, or outsource the technology integral to our business from third parties. Our commercial success will depend in part on these sources of technology and assumes that such sources will not infringe on the proprietary rights of others. We cannot be certain whether any third-party patents will require us to utilize or develop alternative technology or to alter our business plan, obtain additional licenses, or cease activities that infringe on third-parties intellectual property rights. Our inability to acquire any third-party licenses, or to integrate the related third-party products into our business plan, could result in delays in development unless and until equivalent products can be identified, licensed, and integrated. Existing or future licenses may not continue to be available to us on commercially reasonable terms or at all. Litigation, which could result in substantial cost to us, may be necessary to enforce any patents licensed to us or to determine the scope and validity of third-party obligations.

Table of Contents

Our patented GARP technology may not result in a commercial service or product.

We have developed and field tested our artificial lift technology, GARP (Gas Assisted Rod Pump), that we hope to commercialize, though it may not generate material value. Our success in commercializing the technology will depend upon additional positive field tests, acceptance by industry and our ability to defend the technology from competitors through confidentiality and patent protection.

Regulatory and accounting requirements may require substantial reductions in reporting proven reserves.

We review on a periodic basis the carrying value of our crude oil and natural gas properties under the applicable rules of the various regulatory agencies, including the SEC. Under the full cost method of accounting that we use, the after-tax carrying value of our oil and natural gas properties may not exceed the present value of estimated future net after-tax cash flows from proved reserves, discounted at 10%. Application of this ceiling test requires pricing future revenues at the previous 12-month average beginning-of-month price and requires a write down of the carrying value for accounting purposes if the ceiling is exceeded. We may in the future be required to write down the carrying value of our crude oil and natural gas properties when crude oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend in part on the prices for crude oil and natural gas during the previous period and the effect of reserve additions or revisions and capital expenditures during such period. If a write down is required, it would result in a current charge to our earnings but would not impact our current cash flow from operating activities.

Our profitability is highly dependent on the prices of crude oil, natural gas, and natural gas liquids, which have historically been very volatile.

Our estimated proved reserves, revenues, profitability, operating cash flow and future rate of growth are highly dependent on the prices of crude oil, natural gas and NGLs, which are affected by numerous factors beyond our control. Historically, these prices have been very volatile and are likely to remain volatile in the future. A significant and extended downward trend in commodity prices would have a material adverse effect on our revenues, profitability and cash flow, and could result in a reduction in the carrying value of our oil and natural gas properties and the amounts of our estimated proved oil and natural gas reserves. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil and natural gas prices may adversely affect our financial position.

We may be unable to acquire and develop the additional oil and natural gas reserves that are required in order to sustain our business operations.

In general, the volumes of production from crude oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire properties containing proved reserves or conduct successful development activities, or both, our proved reserves will decline. Our future crude oil and natural gas production is, therefore, highly dependent upon our level of success in finding or acquiring additional reserves. Due to decline characteristics of our Giddings wells, our near-term future growth and financial condition are dependent upon our ability to realize production increases expected at Delhi, and /or the development of additional oil and natural gas reserves.

We are subject to substantial operating risks that may adversely affect our results of operations.

The crude oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, hurricanes, flooding, pollution, releases of toxic gas and other environmental hazards and risks. We could suffer substantial losses as a result of any of these events. While we carry general liability, control of well, and operator s extra expense coverage typical in our industry, we are not fully insured against all risks incident to our business.

We may not be the operator of some of our wells in the future, and we are not the operator of our high value assets in the Delhi Field. As a result, our operating risks for those wells and our ability to influence the operations for these wells will be less subject to our control. Operators of these wells may act in ways that are not in our best interests. If this occurs, the development of, and production of crude oil and natural gas from, some wells may not occur timely or at all, which would have an adverse effect on our results of operations.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers, the loss of any of whom could have a material adverse effect on our operations. In particular, our future success is dependent upon Robert S. Herlin, our Chairman, President and Chief Executive Officer, Sterling H. McDonald, our Vice President and Chief Financial Officer, and Daryl V. Mazzanti, our Vice-President of Operations, for sourcing, evaluating and closing deals, capital raising, and oversight of development and operations. Presently, the Company is not a beneficiary of any key man insurance.

Table of Contents

The loss of any of our skilled technical personnel could adversely affect our business.

We depend to a large extent on the services of skilled technical personnel to lease, drill, complete, operate and maintain our crude oil and natural gas fields. We do not have the resources to perform all of these services and therefore we outsource many of our requirements. Additionally, as our production increases, so does our need for such services. Generally, we do not have long-term agreements with our drilling and maintenance service providers. Accordingly, there is a risk that any of our service providers could discontinue servicing our crude oil and natural gas fields for any reason. Although we believe that we could establish alternative sources for most of our operational and maintenance needs, any delay in locating, establishing relationships, and training our sources could result in production shortages and maintenance problems, with a resulting loss of revenue to us. We also rely on third-party carriers for the transportation and distribution of our production, the loss of any of which could have a material adverse effect on our operations.

We may have difficulty managing future growth and the related demands on our resources and may have difficulty in achieving future growth.

Although we hope to experience growth through acquisitions and development activity, any such growth may place a significant strain on our financial, technical, operational and administrative resources. Our ability to grow will depend upon a number of factors, including:

- our ability to identify and acquire new development or acquisition projects;
- our ability to develop existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;
- the success of our technologies;
- hydrocarbon prices;
- drilling, completion and equipment prices;
- our ability to successfully integrate new properties;
- our access to capital; and
- the Delhi Field operator s ability to: deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome, secure all of the development capital necessary to fund its and Evolution s cost interests and to successfully manage technical, strategic and logistical development and operating risks.

We cannot assure you that we will be able to successfully grow or manage any such growth.

We face strong competition from larger oil and gas companies.

Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than ours. We may not be able to successfully conduct our operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment. Specifically, these larger competitors may be able to pay more for development projects and productive crude 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. In addition, such companies may be able to expend greater resources on hiring contract service providers, obtaining oilfield equipment and acquiring the existing and changing technologies that we believe are and will be increasingly important to attaining success in our industry.

Our crude oil and natural gas reserves are only estimates and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their estimated values. Our reserves are only estimates that may prove to be inaccurate because of these uncertainties. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable crude oil and natural gas reserves depend upon a number of variable factors, such as historical production from the area compared with production from other producing areas and assumptions concerning effects of regulations by governmental agencies, future crude oil and natural gas product prices, future operating costs, severance and excise taxes, development costs and work-over and remedial costs. Some or all of these assumptions may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from prepared by different engineers or by the same engineers but at different times, may vary substantially.

Table of Contents

Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the crude oil and natural gas industry in general. PV-10 does not necessarily correspond to market value.

We cannot market the crude oil and natural gas that we produce without the assistance of third parties.

The marketability of the crude oil and natural gas that we produce depends upon the proximity of our reserves to, and the capacity of, facilities and third-party services, including crude oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities necessary to make the products marketable for end use. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in or delay or discontinuance could adversely affect our financial condition. In addition, federal and state regulation of crude oil and natural gas production and transportation could affect our ability to produce and market our crude oil and natural gas on a profitable basis.

Our operations require significant amounts of capital and additional financing may be necessary in order for us to continue our exploration activities, including meeting certain drilling obligations under our existing lease obligations.

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisitions, exploitation and development activities. Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production is established. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our current production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available to us on favorable terms.

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

Some of our properties, including our Delhi interests and our acreage in the Mississippi Lime Play in Oklahoma, are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, result in lower production and materially and adversely affect our financial conditions and results of operations.

We are, and in the future may become, involved in legal proceedings related to our Delhi interest and, as a result, may incur substantial costs in connection with those proceedings.

On August 23, 2012, we, and our wholly owned subsidiary NGS Sub Corp and Robert S. Herlin, our President, were served with a lawsuit filed in federal court by James H. and Kristy S. Jones. The plaintiffs allege primarily that the defendants wrongfully purchased the plaintiffs 0.048119 overriding royalty interest in the Delhi Unit in January 2006 by failing to divulge the existence of an alleged previous agreement to develop the Delhi Field for EOR. Although we believe that the claims are without merit and not timely, and intend to vigorously defend against the claims, an adverse resolution of this proceeding could subject us to significant monetary damages and other penalties, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Table of Contents

Risks Relating to the Oil and Gas Industry

Crude oil and natural gas development, re-completion of wells from one reservoir to another reservoir, restoring wells to production and drilling and completing new wells are speculative activities and involve numerous risks and substantial uncertain costs.

Our growth will be materially dependent upon the success of our future development program. Drilling for crude oil and natural gas and re-working existing wells involve numerous risks, including the risk that no commercially productive crude oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- unexpected drilling conditions;
- pressure fluctuations or irregularities in formations;
- equipment failures or accidents;
- inability to obtain or maintain leases on economic terms, where applicable;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as hydraulic fracturing, horizontal drilling or CO_2 injection or other injectants do not guarantee that we will find and produce crude oil and/or natural gas in our wells in economic quantities. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition. We cannot assure you that our overall drilling success rate or our drilling success rate for activities within a particular geographic area will not decline. We may identify and develop prospects through a number of methods, some of which do not include horizontal drilling, hydraulic fracturing or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. Our drilling schedule and costs may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted prospects will be dependent on a number of factors, including, but not limited to:

- the results of previous development efforts and the acquisition, review and analysis of data;
- the availability of sufficient capital resources to us and the other participants, if any, for the drilling of the prospects;
- the approval of the prospects by other participants, if any, after additional data has been compiled;

- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for crude oil and natural gas and the availability of drilling rigs and crews;
- our financial resources and results;
- the availability of leases and permits on reasonable terms for the prospects; and
- the success of our drilling technology and our ability to control these operations.

We cannot assure you that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive crude oil or natural gas. There are numerous uncertainties in estimating quantities of proved reserves, including many factors beyond our control.

Crude oil and natural gas prices are highly volatile in general and low prices will negatively affect our financial results.

Our revenues, operating results, profitability, cash flow, future rate of growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of crude oil and natural gas. Lower crude oil and natural gas prices also may reduce the amount of crude oil and natural gas that we can produce economically. Historically, the markets for crude oil and natural gas have been very volatile, and such markets are likely to continue to be volatile in the future. Prices for crude oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and domestic supplies of crude oil, natural gas and NGLs;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political instability or armed conflict in oil-producing regions;
- the price and level of foreign imports; and
- overall domestic and global economic conditions.

It is extremely difficult to predict future crude oil and natural gas price movements with any certainty. Declines in crude oil and natural gas prices may materially adversely affect our financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Further, crude oil and natural gas prices do not move in tandem. Because approximately 87% of our proved

Table of Contents

reserves at June 30, 2012 are crude oil reserves and 4% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices.

Oil field service and materials prices may increase, and the availability of such services may be inadequate to meet our needs.

Our business plan to develop or redevelop crude oil and natural gas resources requires third party oilfield service vendors and various materials such as steel tubulars, which we do not control. Long lead times and spot shortages may prevent us from, or delay us in, maintaining or increasing the production volumes we expect. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelop plans.

Government regulation and liability for environmental matters may adversely affect our business and results of operations.

Crude oil and natural gas operations are subject to extensive federal, state and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil and natural gas wells below actual production capacity in order to conserve supplies of crude oil and natural gas. There are federal, state and local laws and regulations primarily relating to protection of human health and the environment applicable to the development, production, handling, storage, transportation and disposal of crude oil and natural gas, by-products thereof and other substances and materials produced or used in connection with crude oil and natural gas operations. In addition, we may inherit liability for environmental damages, whether actual or not, caused by previous owners of property we purchase or lease or nearby properties. As a result, we may incur substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us, such as diminishing the demand for our products through legislative enactment of proposed new penalties, fines and/or taxes on carbon that could have the effect of raising prices to the end user.

For example, currently proposed federal legislation, that, if adopted, could adversely affect our business, financial condition and results of operations, includes the following:

- *Taxes.* President Obama s Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted , make significant changes to U.S. tax laws. These changes include, but are not limited to (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural-gas exploration and development, and (iii) implementing certain international tax reforms, and

- *Hydraulic Fracturing.* The U.S. Congress, the EPA and various states are currently considering legislation that could adversely affect the use of the hydraulic-fracturing process. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. This legislation, if adopted, could establish an additional level of regulation, permitting and restrictions at the federal level that could adversely affect the development of unconventional oil and natural gas resources.

We could be adversely affected by a weak domestic or global economy.

The current anemic recovery from a recessionary economic environment has limited the recovery in demand for oil and natural gas and, therefore, in commodity prices, particularly natural gas. If the current economic environment continues, lower realized prices may adversely impact our profitability. These factors could negatively impact our operations and may limit our growth.

Ownership of our oil, gas and mineral production depends on good title to our property.

Good and clear title to our oil, gas and mineral properties is important. Although title reviews will generally be conducted prior to the purchase of most oil, gas and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction or elimination of the revenue received by us from such properties.

Table of Contents

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If the economic recovery in the United States or abroad remains prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors , suppliers and customers ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Risks Associated with Our Stock

Our stock price has been and may continue to be very volatile.

Our common stock is thinly traded and the market price has been, and is likely to continue to be, highly volatile. For example, during the year prior to June 30, 2012, our stock price as traded on the NYSE Amex ranged from $6.01 to $10.14. The variance in our stock price makes it extremely difficult to forecast with any certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to wide fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- naked short selling of our common stock and stock price manipulation;
- changes or fluctuations in the commodity prices of crude oil and natural gas;
- general conditions and trends in the crude oil and natural gas industry;
- redemption demands on institutional funds that hold our stock; and
- general economic, political and market conditions.

Our executive officers, directors and affiliates may be able to control the election of our directors and all other matters submitted to our stockholders for approval.

Our executive officers and directors, in the aggregate, beneficially own approximately 6.3 million shares, or approximately 19.6% of our beneficial common stock base. JVL Advisors LLC controls approximately 5.0 million shares or approximately 18% of our outstanding common stock. As a result, these holders could exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

The market for our common stock is limited and may not provide adequate liquidity.

Our common stock is currently thinly traded on the NYSE MKT. In the year prior to June 30, 2012, the actual daily trading volume in our common stock ranged from 20,900 shares of common stock to a high of 390,300 shares of common stock traded, with 194 days exceeding a trading volume of 50,000 shares. On most days, this trading volume means there is limited liquidity in our shares of common stock. Selling our shares is more difficult because smaller quantities of shares are bought and sold and news media coverage about us is limited. These factors result in a limited trading market for our common stock and therefore holders of our stock may be unable to sell shares purchased, should they desire to do so.

If securities or industry analyst do not publish research reports about our business, or if they downgrade our stock, the price of our common stock could decline.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. However, to our knowledge, only four independent analysts cover our company. The lack of published reports by independent securities analysts could limit the interest in our common stock and negatively affect our stock price. We do not have any control over the research and reports these analysts publish or whether they will be published at all. If any analyst who does cover us downgrades our stock, our stock price could decline. If any analyst ceases coverage of our company or fails to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price to decline.

Table of Contents

The issuance of additional common stock and preferred stock could dilute existing stockholders.

From time to time, we may have an effective shelf registration that allows us to publicly offer various securities, including common or preferred stock, and at any time we may make private offerings of our securities. We are authorized to issue up to 100,000,000 shares of common stock. To the extent of such authorization, our board of directors has the ability, without seeking stockholder approval, to issue additional shares of common stock in the future for such consideration as our board may consider sufficient. The issuance of additional common stock in the future would reduce the proportionate ownership and voting power of the common stock now outstanding. We are also authorized to issue up to 5,000,000 shares of preferred stock , the rights and preferences of which may be designated in series by our board of directors, of which, at least 317,319 shares of Series A Preferred Stock are issued and outstanding as of September 12, 2012. Such designation of new series of preferred stock may be made without stockholder approval, and could create additional securities which would have dividend and liquidation preferences over the common stock now outstanding. Preferred stockholders could adversely affect the rights of holders of common stock by:

- exercising voting, redemption and conversion rights to the detriment of the holders of common stock;
- receiving preferences over the holders of common stock regarding our surplus funds in the event of our dissolution, liquidation or the payment of dividends to Preferred stockholders;
- delaying, deferring or preventing a change in control of our company; and
- discouraging bids for our common stock.

We do not plan to pay any cash dividends on our common stock.

We have not paid any dividends on our common stock to date and do not anticipate that we will be paying dividends in the foreseeable future. Any payment of cash dividends on our common stock in the future will be dependent upon the amount of funds legally available, our earnings, if any, our financial condition, restrictions contained in our Series A preferred stock and any debt instruments, our anticipated capital requirements and other factors that our board of directors may think are relevant. However, we currently intend for the foreseeable future to follow a policy of retaining all of our earnings, if any, to finance the development and expansion of our business and, therefore, do not expect to pay any dividends on our common stock in the foreseeable future.

Our Series A Preferred Stock is thinly traded and has no stated maturity date.

The shares of Series A Preferred Stock were listed for trading on the NYSE MKT under the symbol EPM.PR.A on July 5, 2011 and are thinly traded on the NYSE MKT. Since the securities have no stated maturity date, investors seeking liquidity will be limited to selling their shares in the secondary market. An active trading market for the shares may not develop or, even if it develops, may not last, in which case the trading price of the shares could be adversely affected and your ability to transfer your shares of Series A Preferred Stock will be limited.

The market value of our Series A Preferred Stock could be adversely affected by various factors.

The trading price of the shares of Series A Preferred Stock may depend on many factors, including:

- market liquidity;
- prevailing interest rates;
- the market for similar securities;
- general economic conditions; and
- our financial condition, performance and prospects.

For example, higher market interest rates could cause the market price of the Series A Preferred Stock to decrease.

We could be prevented from paying dividends on our Series A Preferred Stock.

Although dividends on the Series A Preferred Stock are cumulative and arrearages will accrue until paid, you will only receive cash dividends on the Series A Preferred Stock if we have funds legally available for the payment of dividends and such payment is not restricted or prohibited by law, the terms of any senior shares or any documents governing our indebtedness. Our business may not generate sufficient cash flow from operations to enable us to pay dividends on the Series A Preferred Stock when payable. In addition, existing or future debt, credit facility arrangements, contractual covenants or arrangements we enter into may restrict or prevent future dividend payments. Accordingly, there is no guarantee that we will be able to pay any cash dividends on our Series A Preferred Stock.

Table of Contents

Furthermore, in some circumstances, we may pay dividends in stock rather than cash, and our stock price may be depressed at such time.

Our Series A Preferred Stock has not been rated and will be subordinated to all of our existing and future debt.

Our Series A Preferred Stock has not been rated by any nationally recognized statistical rating organization. In addition, with respect to dividend rights and rights upon our liquidation, winding-up or dissolution, the Series A Preferred Stock will be subordinated to any existing and future debt and all future capital stock designated as senior to the Series A Preferred Stock. We may also incur additional indebtedness in the future to finance potential acquisitions or the development of new properties and the terms of the Series A Preferred Stock do not require us to obtain the approval of the holders of the Series A Preferred Stock prior to incurring additional indebtedness. As a result, our existing and future indebtedness may be subject to restrictive covenants or other provisions that may prevent or otherwise limit our ability to make dividend or liquidation payments on our Series A Preferred Stock. Upon our liquidation, our obligations to our creditors would rank senior to our Series A Preferred Stock and would be required to be paid before any payments could be made to holders of our Series A Preferred Stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Company Location

Our corporate headquarters are located at 2500 CityWest Boulevard, Suite 1300, Houston, Texas. We entered into a sublease agreement, effective on March 1, 2007, to rent approximately 8,400 square feet of Class A office space in the Westchase District area in West Houston. The current monthly base rent is $13,251, having escalated from a monthly base rate of $11,507 in August 2011. The sublease expires by its term on July 1, 2016.

Oil & Gas Properties

Additional detailed information describing the types of properties we own can be found in Business Strategy under *Item 1. Business* of this Form 10-K.

Table of Contents

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

In December 2008, the SEC adopted new rules related to modernizing reserve estimation and disclosure requirements for oil and natural gas companies (the Modernization Requirements), which became effective for annual reporting periods ending on or after December 31, 2009. The Modernization Requirements require disclosure of oil and gas proved reserves by significant geographic area, using the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

There are numerous uncertainties inherent in estimating quantities of proved reserves and estimates of reserves quantities and values must be viewed as being subject to significant change as more data about the properties becomes available.

Estimated future net revenues discounted at 10% or PV-10 is a financial measure that is not recognized by GAAP. We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies, and that it is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. Further, analysts and investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies reserves. We also use this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our Company. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure as defined under GAAP, and reconciled herein.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2012

Our proved and probable reserves at June 30, 2012, denominated in equivalent barrels using six Mcf of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum engineers, W.D. Von Gonten & Co. (Von Gonten) and DeGolyer and MacNaughton (D&M). Von Gonten was engaged for our Texas properties due to their particular expertise in the geographic and geologic areas covered by their reports. D&M was selected for our interests in the Delhi Field due to their expertise in CO2-EOR projects and to ensure consistency with the Operator who has utilized D&M for their reserves estimates in the Delhi Field. Our probable reserves in Oklahoma were estimated by Pinnacle Energy Services L.L.C. due to their particular expertise in Oklahoma and the Mississippian Lime reservoir. The scope and results of their procedures are summarized in letters from each of those firms, which are included as exhibits to this Annual Report on Form 10-K.

The following table sets forth our estimated proved and probable reserves as of June 30, 2012. See Note 17 to the consolidated financial statements, where additional unaudited reserve information is provided. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $95.67 per barrel of crude oil and $3.15 per MMbtu of natural gas. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. Pricing differentials were applied to all properties, on an individual property basis. Quality adjustments have been applied based on actual BTU factors for each well and a shrinkage factor has been applied based on production volumes versus actual sales volumes.

June 30, 2012

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)		PV-10
PROVED						
Developed (60% of Proved)	7,671	112	1,499	8,033	$	335,956,852
Undeveloped (40% of Proved)	3,967	381	6,361	5,408		109,557,773
TOTAL PROVED	11,638	493	7,860	13,441	$	445,514,625
Product Mix	87%	4%	9%	100%		
PROBABLE						
Developed (21% of Probable)	2,653			2,653	$	58,235,794
Undeveloped (79% of Probable)	7,255		16,620	10,025		116,091,943
TOTAL PROBABLE	9,908		16,620	12,678	$	174,327,737
Product Mix	78%		22%	100%		

Table of Contents

Summary of Oil & Gas Reserves for Fiscal Year Ended 2011

Our proved and probable reserves at June 30, 2011, denominated in equivalent barrels using six Mcf of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum engineers, W.D. Von Gonten & Co. (Von Gonten), DeGolyer and MacNaughton (D&M), and Lee Keeling and Associates, Inc. (Keeling). Von Gonten and Keeling were engaged for our Texas and Oklahoma properties, respectively, due to their particular expertise in the geographic and geologic areas covered by their reports. D&M was selected for our properties in the Delhi Field due to their expertise in CO2-EOR projects and to ensure consistency with the Operator who has utilized D&M for their reserves estimates in the Delhi Field. The scope and results of their procedures are summarized in letters from each of those firms, which are included as exhibits to this Annual Report on Form 10-K.

The following table sets forth our estimated proved reserves as of June 30, 2011. See Note 17 to the consolidated financial statements, where additional unaudited reserve information is provided. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $90.09 per barrel of crude oil and $4.21 per MMbtu of natural gas. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. Pricing differentials were applied to all properties, on an individual property basis. Quality adjustments have been applied based on actual BTU factors for each well and a shrinkage factor has been applied based on production volumes versus actual sales volumes.

June 30, 2011

Reserve Category	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total Reserves (MBOE)**		**PV-10**
PROVED						
Developed (39% of Proved)	4,986	101	1,543	5,345	$	200,532,776
Undeveloped (61% of Proved)	6,582	611	7,861	8,503		174,805,682
TOTAL PROVED	11,568	712	9,404	13,848	$	375,338,458
Product Mix	84%	5%	11%	100%		
PROBABLE						
Developed (31% of Probable)	1,902			1,902	$	33,688,710
Undeveloped (69% of Probable)	4,314			4,314		41,918,888
TOTAL PROBABLE	6,216			6,216	$	75,607,598
Product Mix	100%			100%		

Summary of Oil & Gas Reserves for Fiscal Year Ended 2010

Our proved and probable reserves at June 30, 2010, denominated in equivalent barrels using a six Mcf of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum consultants, W.D. Von Gonten & Co. (Von Gonten), DeGolyer and MacNaughton (D&M), and Lee Keeling and Associates, Inc. (Keeling). Von Gonten and Keeling were engaged for our Texas and Oklahoma properties, respectively, due to their particular expertise in the geographic and geologic areas covered by their reports. D&M was selected for our properties in the Delhi Field due to their expertise in CO2-EOR projects and to ensure consistency with the Operator who has utilized D&M for their reserves estimates in the Delhi Field. The scope and results of their procedures are summarized in letters from each of those firms, which are included as exhibits to this Annual Report on Form 10-K.

Table of Contents

The following table sets forth our estimated proved reserves as of June 30, 2010. See Note 17 to the consolidated financial statements, where additional reserve information is provided. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $76.45 per barrel of crude oil and $4.09 per MMbtu of natural gas. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. Pricing differentials were applied to all properties, on an individual property basis. Quality adjustments have been applied based on actual BTU factors for each well and a shrinkage factor has been applied based on production volumes versus actual sales volumes.

June 30, 2010

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)		PV-10
PROVED						
Developed (9% of Proved)	706	158	1,537	1,119	$	31,722,014
Undeveloped (91% of Proved)	9,549	879	5,226	11,299		234,256,329
TOTAL PROVED	10,255	1,037	6,763	12,418	$	265,978,343
Product Mix	83%	8%	9%	100%		
PROBABLE						
Developed (4% of Probable)	301			301	$	5,955,480
Undeveloped (96% of Probable)	5,870	226	4,632	6,868		57,837,249
TOTAL PROBABLE	6,171	226	4,632	7,169	$	63,792,729
Product Mix	86%	3%	11%	100%		

Table of Contents

Changes in Oil and Gas Reserves

During our fiscal year ended June 30, 2012, total proved reserves declined 406 MBOE from 13,847 MBOE at June 30, 2011 to 13,441 MBOE at June 30, 2012. The decrease is primarily attributable to 208 MBOE of production, downward revisions for our Woodford properties in Oklahoma and lease terminations in Giddings Fields, partially offset by an upward revision at Delhi and extensions in South Texas and acquired well bores in the Giddings Fields. The upward revision of 210 MBO in proved oil reserves in the Delhi Field is due primarily to a slight acceleration in the projected reversion date of our approximately 24% working interest based on performance to date. The downward revision of 367 MBOE in Giddings is primarily due to our election to allow certain leases containing proved reserves to expire due to unacceptable economics based on low natural gas prices. The additions and revisions in our properties were offset by production of 208 MBOE. See table below for details.

Major changes in reserve categories and significant additions to probable reserves also occurred during fiscal 2012. Proved developed reserves increased to 60% of proved reserves, a 54% improvement from 39% of proved reserves that were developed at June 30, 2011. The 2,688 MBO increase in proved developed reserves was largely due to development activities at Delhi, wherein the operator expended $96 million of their capital for the benefit our combined accounts. We also experienced two major changes in our probable reserves during fiscal 2012. First, probable reserves increased104% increase over the 6,216 MBOE level at the end of fiscal 2011, to 12,678 MBOE. Virtually all of the 6,462 MBOE increase in probable reserves was due to the undeveloped acreage positions we acquired in the Mississippian Lime play we acquired in Kay County, OK during fiscal 2012. Secondly, probable developed reserves at Delhi increased 39% to 2,653 MBO from 1,902 MBO at yearend fiscal 2011, due to capital expenditures mentioned above. See tables immediately above.

During our fiscal year ended June 30, 2011, total proved reserves increased 1,430 MBOE from 12,418 MBOE at June 30, 2010 to 13,848 MBOE at June 30, 2011. The increase is primarily attributable to upward revisions in both our Delhi and Giddings Fields, partially offset by sales in place of reserves in the Giddings Field. The upward revision of 1,570 MBO in proved oil reserves in the Delhi Field is due primarily to a more than two year acceleration in the projected reversion date of our 24% working interest resulting based on performance to date. The upward revision of 331 MBOE in Giddings is primarily due to re-categorizing probable reserves into the proved category due to drilling results during the year, partially offset by highgrading our portfolio and performance of certain wells. Sales in place of 522 MBOE in the Giddings Field are primarily due to the industry drilling joint venture we entered into early in the year. We also restored 61 MBO of proved reserves in South Texas due to positive test and production results during the year and added 130 MBOE of proved reserves in our Haskell county, Oklahoma gas shale property, net of a downward revision due to a de-emphasis of the Wagoner County properties. The additions and revisions in our properties were offset by production of 116 MBOE.

Major changes in probable reserves during fiscal 2011 included a 13%, or 953 MBOE, decrease in probable reserves to 6,216 MBOE. The decrease was due to allowing leases covering probable reserves in the Giddings Field to expire due to commodity prices. At Delhi, probable developed reserves increased 1,601 MBO from 301 MBO at yearend fiscal 2011 to 1,902 MBO at fiscal yearend 2012.

	Delhi Field	**Giddings Field**	**Lopez Field**	**Oklahoma**	**Total**
Proved reserves, MBOE					
June 30, 2010	9,411.8	2,983.5		22.9	12,418.2
Production	(44.1)	(71.3)	(0.6)	(0.4)	(116.4)
Revisions	1,569.7	330.3	61.8	(22.9)	1,938.9
Sales of minerals in place		(521.7)			(521.7)
Improved recovery, extensions and discoveries				128.5	128.5

June 30, 2011	10,937.4	2,720.8	61.2	128.1	13,847.5
Production	(136.1)	(69.3)	(1.8)	(1.0)	(208.2)
Revisions	210.3	(367.4)	(60.2)	(127.1)	(344.4)
Sales of minerals in place					
Improved recovery, extensions and discoveries		39.7	106.5		146.2
June 30, 2012	11,011.6	2,323.8	105.7		13,441.1

Reconciliation of PV-10 to the Standardized Measure of Discounted Future Net Cash Flows

The following table provides a reconciliation of PV-10 of all of our proved properties to the Standardized Measure as shown in Note 17 of the consolidated financial statements.

Table of Contents

	For the Years Ended June 30 2012	2011
Estimated future net revenues	$ 858,510,526	$ 741,212,773
10% annual discount for estimated timing of future cash flows	(412,995,901)	(365,874,315)
Estimated future net revenues discounted at 10% (PV-10)	445,514,625	375,338,458
Estimated future income tax expenses discounted at 10%	(161,917,132)	(146,890,504)
Standardized Measure	$ 283,597,493	$ 228,447,954

Table of Contents

The following table provides a reconciliation of PV-10 of each of our proved properties to the Standardized Measure as shown in Note 17 of the consolidated financial statements.

	For the Years Ended June 30	
	2012	2011
Delhi Field	$ 409,117,412	$ 333,618,884
Giddings Field	35,609,294	40,800,575
Lopez Field	787,919	470,319
Oklahoma		448,680
Estimated future net revenues discounted at 10% (PV-10)	$ 445,514,625	$ 375,338,458
Estimated future income tax expenses discounted at 10%	(161,917,132)	(146,890,504)
Standardized Measure	$ 283,597,493	$ 228,447,954

Additional detailed information describing the types of properties we own can be found in Item 1. Business Business Strategy.

Internal Controls Over Reserves Estimation Process and Qualifications of Technical Persons with Oversight for the Company s Overall Reserve Estimation Process

Our policies regarding internal controls over reserve estimates require reserves to be prepared by an independent engineering firm under the supervision of our Chief Executive Officer and Vice President of Operations and to be in compliance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. We provide each engineering firm with property interests, production, current operating costs, current production prices and other information. This information is reviewed by our Vice President of Operations and our Chief Executive Officer to ensure accuracy and completeness of the data prior to submission to our third party engineering firm. The scope and results of our third party engineering firms procedures are summarized in a letter included as an exhibit to this Annual Report on Form 10-K. A letter which identifies the professional qualifications of each of the independent engineering firms who prepared the reserve reports are also filed as exhibits to this Annual report on Form 10-K.

Proved Undeveloped Reserves

Our proved undeveloped reserves at June 30, 2012 were 5,408 MBOE. Future development costs associated with our proved undeveloped reserves at June 30, 2012 totaled approximately $37.0 million. The 3,095 MBOE decrease in proved undeveloped reserves from 8,503 MBOE as of June 30, 2011 is primarily attributable to the reclassification of 2,562 MBbls of proved undeveloped oil reserves to the proved developed category in our Delhi Field.

None of our proved undeveloped locations at June 30, 2012 have remained undeveloped for five years from the date of initial recognition as proved undeveloped reserves.

26

Table of Contents

Sales Volumes, Average Sales Prices and Average Production Costs

The following table shows the Company s sales volumes and average sales prices received for crude oil, natural gas liquids, and natural gas for the periods indicated:

	Year Ended June 30, 2012		Year Ended June 30, 2011		Year Ended June 30, 2010	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Crude oil (Bbls)	151,081	$ 109.53	57,965	$ 97.86	29,749	$ 73.56
Natural gas liquids (Bbls)	12,611	$ 49.18	18,704	$ 47.77	27,820	$ 38.80
Natural gas (Mcf)	266,777	$ 2.98	238,608	$ 4.04	407,674	$ 4.30

Average production costs, including production taxes, per unit of production (using a six to one conversion ratio of Mcf s to barrels) were approximately $9, $12 and $13 per BOE for the years ended June 30, 2012, 2011 and 2010, respectively.

Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2012 increased 79% to 208,155 BOE, compared to 116,437 BOE for the year ended June 30, 2011. Our sales volumes for the year ended June 30, 2012 included 136,075 Bbls of oil from Delhi compared to 44,141 Bbls of oil during the previous fiscal year, and 72,080 BOE in aggregate from our Giddings and Lopez Fields in Texas and our Oklahoma properties, compared to 72,296 BOE during the previous fiscal year.

Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2011 decreased 7% to 116,437 BOE, compared to 125,515 BOE for the year ended June 30, 2010. Our sales volumes for the year ended June 30, 2011 included 44,141 Bbls of oil from Delhi compared to 6,333 Bbls of oil during the previous fiscal year and 71,010 BOE from our properties in the Giddings Field in Texas compared to 119,182 BOE during the previous fiscal year.

First EOR oil production at Delhi began in mid-March 2010. Our interests in the Delhi Field comprise approximately 82% of our total proved reserves as of June 30, 2012. The average sales price per barrel of crude oil at Delhi was $111.29 for the year ended June 30, 2012, with no associated production costs.

Production from our properties in the Giddings Field decreased 3% from 71,280 BOE during the fiscal year ended June 2011 to 69,260 BOE during the fiscal year ended June 30, 2012. Our interests in the Giddings Field consist of 17% of our total proved reserves as of June 30, 2012. The average sales price per BOE at Giddings was $37.89 for the year ended June 30, 2012. The associated production cost in Giddings for the year ended June 30, 2012 (not including ad valorem and production taxes) was $15.26 per BOE.

Drilling Activity

The following table sets forth our drilling activity. During 2012 we drilled and completed one gross and net well in the Lopez Field, declared dry two wells in Wagoner County, Oklahoma, and plugged and abandoned one well in our Giddings Field. One well drilled in the Lopez Field is temporarily inactive pending permitting. In 2011, we drilled and completed 3 gross and 0.6 net wells in the Giddings Field. One gross and net well drilled in 2010 in Wagoner County, Oklahoma was plugged and abandoned during 2011 as a dry hole.

	Year Ended June 30,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Productive wells drilled						
Development			3.0	0.6	1.0	1.0
Exploratory	1.0	1.0				
Total	1.0	1.0	3.0	0.6	1.0	1.0
Nonproductive dry wells drilled						
Development						
Exploratory			1.0	1.0		
Total			1.0	1.0		

Table of Contents

Present Activities

As of June 30, 2012 there were 2 gross and 0.8 net wells in Kay County, Oklahoma awaiting completion or in the process of drilling and one gross and 0.45 net salt water disposal well also drilled and completed.

Wells previously drilled and completed waiting on pipeline as of June 30, 2011 in Wagoner County, Oklahoma remain shut-in and we do not expect to establish pipeline connections prior to sale or lease expiration. One well acquired and re-entered in 2011 and completed in 2012 in Haskell County, Oklahoma was established as a producing well with 5.8 MMCF of sales during 2012. As of June 30, 2012, that well was temporarily shut-in.

Two gross and net wells were drilled and completed, but waiting on permit, as of June 30, 2012 in the Lopez Field in Texas. One of the wells is a salt water injection well and one is a producer well.

The operator of the Delhi Field continued to expand the project through drilling and well re-entering activities during 2012. CO_2 injection was increased during the year as additional injection wells were added during the year except for temporary capacity issues late in the fourth quarter as discussed at Delhi Field EOR in Management s Discussion and Analysis of Financial Condition and Results of Operations. As our interest in the Delhi Field is currently an ORRI, we do not show gross and net well activity in Delhi.

For further discussion, see Highlights for our fiscal year 2012 and Looking forward into 2012 under *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations* of this Form 10-K.

Delivery Commitments

As of June 30, 2012, we had no delivery commitments.

Productive Wells and Developed Acreage

Area	**Gross Developed Acres**	**Net Developed Acres**	**Gross (Net) Producing Wells**		**Gross (Net) Inactive Producing Wells**	
Giddings	6,302.5	5,004.9	15.0	(12.6)	1.0	(1.0)
Lopez	654.6	654.6	2.0	(2.0)	1.0	(1.0)
OK	253.0	253.0			3.0	(3.0)

Total	7,210.1	5,912.5	17.0	(14.6)	5.0	(5.0)

Our developed acreage at June 30, 2012 totaled 5,912.5 net acres, of which 5,004.9 net acres were in the Giddings Field comprising a 100% working interest in eleven producing wells, a 99% working interest in one well subject to a back-in reversion of 22.5%, and a 20% BPO WI in three producing wells. One producing well in which we have a 99% working interest is currently shut-in. We hold 654.6 net acres in Webb and Duval Counties in South Texas comprising a 100% working interest in two producing wells and a third producer currently shut-in waiting on permit. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. Our proved reserves at Delhi are 68% proved developed, but we do not recognize net acres in the EOR project at Delhi prior to reversion of our working interest.

Our developed acreage at June 30, 2011 totaled 5,362 net acres in the Giddings Field, consisting of a 100% working interest in ten producing wells and a 20% BPO WI in three producing wells, 100 net acres in Haskell County, OK with one 100% WI producing well, 153 net acres in Wagoner County, OK with one 100% WI nonproducing shut-in well and 446 acres in Webb County, Texas with one 100% WI producing well. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. Our proved reserves at Delhi are 45% proved developed, but we do not recognize net acres in the EOR project at Delhi prior to reversion of our working interest.

Our developed acreage at June 30, 2010 totaled 5,040 net acres in the Giddings Field, consisting of a 100% working interest in nine producing and one developed non-producing gross and net wells, and 153 net acres in Wagoner County, OK with one nonproducing shut-in well. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. Our proved reserves at Delhi are 7% proved developed, but we did not recognize net acres at Delhi prior to reversion of our working interest.

Table of Contents

Undeveloped Acreage

As of June 30, 2012, we held approximately gross 41,708 and 20,506 net undeveloped acres in the Gulf Coast and Mid-Continent regions of the United States, as follows:

Undeveloped Acreage

Field/Area	Gross Acreage	Net Acreage
Giddings Field, Texas	3,255	3,145
Woodford, Oklahoma	12,702	8,514
Lopez Field, South Texas	237	237
Kay County, Oklahoma	11,878	5,345
Delhi Field, Louisiana *	13,636	3,265
Total	41,708	20,506

* Includes from the surface of the Earth to the top of the Massive Anhydride, less and except the Delhi Holt Bryant CO_2 and Mengel Units. With respect to the Delhi Holt Bryant Unit, currently being redeveloped using CO_2-EOR operations within this same acreage, we currently own royalty interests aggregating approximately 7.4%. Separately, we own a 23.9% reversionary working interest (19% net revenue interest) that will revert to us, as, if and when payout occurs, as defined. We are not the operator of the Delhi CO_2-EOR project.

Our net undeveloped acreage that is subject to expiration over the next three years, if not renewed or extended by option is approximately 6,823 acres in fiscal 2013, 2,895 acres in fiscal 2014, and 3,304 acres in 2015.

For more complete information regarding current year activities, including crude oil and natural gas production, refer to *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations* of this Form 10-K.

Item 3. Legal Proceedings

See Note 14 Commitments and Contingencies under Item 8. Financial Statements for a description of legal proceedings.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock

Our common stock is currently traded on the NYSE MKT under the ticker symbol EPM .

We initiated trading of our common stock on the OTC Bulletin Board in May 2004, under the symbol NGSY . On July 17, 2006 we qualified for trading on the American Stock Exchange. The American Stock Exchange was acquired by the NYSE Euronext (NYX) in 2008 and is now known as NYSE MKT. The following table shows, for each quarter of fiscal year 2012, 2011 and 2010, the high and low sales prices for EPM as reported by the NYSE MKT.

Table of Contents

NYSE MKT: EPM

2012:		**High**		**Low**
Fourth quarter ended June 30, 2012	$	9.71	$	7.50
Third quarter ended March 31, 2012	$	10.14	$	7.97
Second quarter ended December 31, 2011	$	8.83	$	6.50
First quarter ended September 30, 2011	$	7.85	$	5.90

2011:		**High**		**Low**
Fourth quarter ended June 30, 2011	$	8.80	$	6.44
Third quarter ended March 31, 2011	$	8.39	$	5.52
Second quarter ended December 31, 2010	$	6.85	$	5.50
First quarter ended September 30, 2010	$	6.01	$	4.10

2010:		**High**		**Low**
Fourth quarter ended June 30, 2010	$	6.25	$	4.61
Third quarter ended March 31, 2010	$	5.10	$	4.36
Second quarter ended December 31, 2009	$	4.67	$	2.90
First quarter ended September 30, 2009	$	3.34	$	2.21

Holders

As of June 30, 2012, there were 27,882,224 shares of common stock issued and outstanding, held by approximately 350 holders of record.

Dividends

We have never declared or paid any cash dividends with respect to our common stock, and we do not intend to do so in the near future. We anticipate that we will retain future earnings for use in the operation and expansion of our business and for the payment of dividends on our Series A Perpetual Preferred Stock. Any future determination with regard to the payment of dividends will be at the discretion of the board of directors and will be dependent upon our future earnings, financial condition, applicable dividend restrictions and capital requirements and other factors deemed relevant by the board of directors.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our Common Stock over the period from June 30, 2007 to June 30, 2012 with the cumulative total return of the S&P 500 Index and the SIG Oil Exploration and Production Index of publicly traded companies over the same period. The graph assumes that $100 was invested on June 30, 2007 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any.

The graph is presented in accordance with requirements of the SEC. Shareholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.

Table of Contents

Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding Options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (1)
Equity compensation plans approved by security holders	4,335,320(1)	$	1.89	1,012,111
Equity compensation plans not approved by security holders	1,038,665(2)	$	1.56	
Total	5,373,985	$	1.83	1,012,111

(1) On May 26, 2004, we, as Reality Interactive, Inc., executed an Agreement and Plan of Merger with Natural Gas Systems, Inc., a Delaware corporation (the Merger). In connection with the Merger, we assumed the obligations of 600,000 stock options under our acquired subsidiary s 2003 Stock Option Plan. As of June 30, 2012, 470,000 shares remain issuable upon exercise of stock options under the 2003 Stock Option Plan and no further options shall be issued there under. As of June 30, 2012, there were 3,945,195 shares of common stock issuable upon exercise of outstanding stock options, 79,875 options that were exercised and 1,542,694 shares of common stock issued directly under the Amended and Restated 2004 Stock Plan, leaving 1,012,111 shares of common stock available for issuance.

(2) In addition to assuming certain obligations listed in footnote 1 above, in connection with the Merger, we also assumed outstanding warrants to purchase shares of common stock issued in connection with arranging the merger and in connection with capital raising. Total warrants outstanding as of June 30, 2012 related to these activities were 1,165 with a weighted average exercise price of $2.50. Also included were 1,037,500 warrants with a weighted average exercise price of $1.56 issued in connection with employment and or compensation arrangements, including a warrant to purchase 287,500 shares of common stock in connection with Mr. Herlin s employment agreement with the Company, a warrant to purchase 200,000 shares in connection with Mr. Mazzanti s employment agreement with the Company, a warrant to purchase 400,000 shares of common stock in connection with Mr. Herlin s annual performance incentives, including warrants in lieu of cash bonus, and a warrant to purchase 150,000 shares of common stock in connection with Mr. McDonald s annual performance incentives, including warrants in lieu of cash bonus.

Recent Sales of Unregistered Securities

On May 3, 2012, the Company sold 65,261 shares of common stock pursuant to a net cashless exercise of placement warrants. The placement warrants, issued to Laird Cagan, a member of our board of directors, in 2005 in connection with a financing transaction, gave Mr. Cagan the right to purchase 91,200 shares, with a weighted average exercise price of $2.50 per share. The shares of common stock were issued to Mr. Cagan pursuant to an exemption from registration afforded under Section 4(2) of the Securities Act of 1933.

Table of Contents

Item 6. Selected Financial Data

The selected consolidated financial data, set forth below should be read in conjunction with Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this report.

	Year Ended June 30				
	2012	**2011**	**2010**	**2009**	**2008**
Income Statement Data					
Revenues	$ 17,962,038	$ 7,530,875	$ 5,021,901	6,095,183	$ 4,256,128
Lease operating expense	1,708,235	1,298,650	1,616,767	1,281,989	1,255,787
Production taxes	66,764	80,677	48,312	158,794	90,252
Depreciation, depletion, and amortization	1,136,974	563,104	1,818,110	2,461,162	903,214
Accretion expense	77,505	59,913	61,054	37,601	20,196
General and administrative expense (G&A) (excluding stock-based compensation)	4,667,291	3,799,377	2,943,843	3,490,466	3,705,751
G&A: Stock-based compensation	1,475,995	1,536,007	2,148,400	2,405,900	1,791,486
Income (loss) from operations	8,829,274	193,147	(3,614,585)	(3,740,729)	(3,510,558)
Other income	3,778	14,214	55,054	122,272	854,130
Income tax provision (benefit)	3,700,922	448,914	(1,171,824)	(1,016,864)	(1,085,454)
Net income (loss) attributable to the Company	$ 5,132,130	$ (241,553)	$ (2,387,707)	$ (2,601,593)	$ (1,570,974)
Dividends on Series A Preferred Stock	630,391				
Net income (loss) attributable to common shareholders	$ 4,501,739	$ (241,553)	$ (2,387,707)	$ (2,601,593)	$ (1,570,974)
Earnings per share:					
Basic	$ 0.16	$ (0.01)	$ (0.09)	$ (0.10)	$ (0.06)
Diluted	$ 0.14	$ (0.01)	$ (0.09)	$ (0.10)	$ (0.06)

Table of Contents

	June 30, 2012	June 30, 2011	June 30, 2010	June 30, 2009	June 30, 2008
Balance Sheet Data					
Total current assets	$ 16,769,789	$ 6,574,312	$ 6,229,351	$ 8,873,786	$ 17,801,070
Total assets	58,955,486	40,168,425	37,195,075	37,828,823	40,365,848
Total current liabilities	5,088,917	2,428,404	1,287,699	1,237,904	4,171,048
Total liabilities	12,332,698	6,703,668	5,717,882	6,072,229	7,362,114
Stockholders equity	46,622,788	33,464,757	31,477,193	31,756,594	33,003,734
Common stock outstanding	27,882,224	27,612,916	27,061,376	26,530,317	26,870,439

	Quarter Ended (unaudited)				
	June 30, 2012	March 31, 2012	December 31, 2011	September 30, 2011	June 30, 2011
Revenues					
Crude oil	$ 4,334,677	$ 4,532,942	$ 4,231,201	$ 3,448,595	$ 2,638,138
Natural gas liquids (NGLs)	120,442	128,319	182,971	188,455	224,062
Natural gas	126,827	187,273	232,530	247,806	303,072
Total operating revenues	4,581,946	4,848,534	4,646,702	3,884,856	3,165,272
Operating Expense					
Lease operating expense (LOE)	430,387	662,461	412,470	202,917	348,268
Production taxes	18,839	15,165	18,725	14,035	26,593
Depreciation, depletion, and amortization	302,623	316,665	280,795	236,891	204,141
Accretion expense	20,793	20,124	19,616	16,972	16,599
G&A (excluding stock-based compensation)	1,339,235	1,206,189	1,133,387	988,480	966,676
G&A: Stock-based compensation	349,960	354,469	354,871	416,695	392,593
Total operating expense	2,461,837	2,575,073	2,219,864	1,875,990	1,954,870
Operating income	2,120,109	2,273,461	2,426,838	2,008,866	1,210,402
Interest income (expense), net	(10,808)	628	6,712	7,246	1,180
Net income before income tax benefit	2,109,301	2,274,089	2,433,550	2,016,112	1,211,582
Income tax provision	1,014,144	805,989	1,008,195	872,594	676,692
Net income attributable to the Company	$ 1,095,157	$ 1,468,100	$ 1,425,355	$ 1,143,518	$ 534,890
Dividends on Preferred Stock	168,576	168,575	165,405	127,835	
Net income attributable to common shareholders	$ 926,581	$ 1,299,525	$ 1,259,950	$ 1,015,683	$ 534,890
Earnings per share					
Basic	$ 0.03	$ 0.05	$ 0.05	$ 0.04	$ 0.02
Diluted	$ 0.03	$ 0.04	$ 0.04	$ 0.03	$ 0.02
Sales volumes per day					
Oil (Bbls)	437.7	445.9	407.8	360.4	256.0
NGL (Bbls)	31.9	33.5	34.2	38.3	44.9
Natural gas (Mcf)	658.7	837.8	759.6	659.9	822.8
Total (BOE)	579.4	619.0	568.5	508.7	438.0
Average sales price					
Oil per Bbl	$ 108.83	$ 111.71	$ 112.79	$ 104.00	$ 113.25
NGL per Bbl	41.53	42.15	58.18	53.51	54.88
Natural gas per Mcf	2.12	2.46	3.33	4.08	4.05
Total per BOE	86.91	86.08	88.84	83.01	79.42
Per BOE					
LOE and production taxes	8.52	12.03	8.24	4.64	9.41
DD&A	5.74	5.62	5.37	5.06	5.12
Accretion expense	0.39	0.36	0.38	0.36	0.42

G&A (excluding stock-based compensation)		25.40		21.41		21.67		21.12		24.25
G&A: Stock-based compensation		6.64		6.29		6.78		8.90		9.85
Total operating expense		46.70		45.72		42.44		40.09		49.05
Operating income	$	40.21	$	40.36	$	46.40	$	42.92	$	30.37
Earnings attributable to common shareholders	$	17.58	$	23.07	$	24.09	$	21.70	$	13.42

Table of Contents

	Quarter Ended (unaudited)				
	June 30, 2011	**March 31, 2011**	**December 31, 2010**	**September 30, 2010**	**June 30, 2010**
Revenues					
Crude oil	$ 2,638,138	$ 1,607,521	$ 778,594	$ 648,218	$ 759,344
Natural gas liquids (NGLs)	224,062	228,050	231,495	209,918	231,460
Natural gas	303,072	181,504	169,343	310,960	368,387
Total operating revenues	3,165,272	2,017,075	1,179,432	1,169,096	1,359,191
Operating Expense					
Lease operating expense (LOE)	348,268	284,577	311,224	354,581	482,160
Production taxes	26,593	26,308	13,073	14,703	8,054
Depreciation, depletion, and amortization	204,141	132,516	102,429	124,018	144,766
Accretion expense	16,599	16,233	10,766	16,315	15,954
G&A (excluding stock-based compensation)	966,676	966,628	912,993	953,081	433,064
G&A: Stock-based compensation	392,593	392,533	396,394	354,486	957,595
Total operating expense	1,954,870	1,818,795	1,746,879	1,817,184	2,041,593
Operating income (loss)	1,210,402	198,280	(567,447)	(648,088)	(682,402)
Interest income, net	1,180	1,562	3,705	7,767	7,269
Net income (loss) before income tax provision (benefit)	1,211,582	199,842	(563,742)	(640,321)	(675,133)
Income tax provision) (benefit)	676,692	29,416	(102,207)	(154,987)	(245,712)
Net income (loss)	$ 534,890	$ 170,426	$ (461,535)	$ (485,334)	$ (429,421)
Net income (loss) per share basic and diluted	$ 0.02	$ 0.01	$ (0.02)	$ (0.02)	$ (0.02)
Weighted average number of common shares outstanding					
Basic	27,612,916	27,521,957	27,457,118	27,160,723	27,137,611
Diluted	31,090,818	30,833,505	27,457,118	27,160,723	27,137,611
Sales volumes per day					
Oil (Bbls) - Delhi	219.6	148.1	68.1	49.5	62.9
Other properties					
Oil (Bbls)	36.3	36.4	33.5	45.2	46.7
NGL (Bbls)	44.9	50.4	54.6	55.1	64.2
Natural gas (Mcf)	822.8	513.6	505.5	771.8	972.7
Total (BOE)	438.0	320.4	240.4	278.5	335.8
Average sales price					
Oil per Bbl - Delhi	$ 115.25	$ 98.89	$ 84.42	$ 75.14	$ 76.48
Other properties					
Oil per Bbl	101.13	88.38	80.98	73.51	75.77
NGL per Bbl	54.88	50.31	46.12	41.41	39.63
Natural gas per Mcf	4.05	3.93	3.64	4.38	4.16
Total per BOE	79.42	69.94	53.32	45.63	44.47
Per BOE					
LOE and production taxes	9.41	10.78	14.66	14.41	16.04
DD&A	5.12	4.59	4.63	4.84	4.74
Accretion expense	0.42	0.56	0.49	0.64	0.52
G&A (excluding stock-based compensation)	24.25	33.52	41.28	37.20	14.17

G&A: Stock-based compensation		9.85		13.61		17.92		13.84		31.33
Total operating expense		49.05		63.06		78.98		70.93		66.80
Operating (loss) income	$	30.37	$	6.88	$	(25.65)	$	(25.30)	$	(22.33)
Net income (loss) before income taxes	$	30.40	$	6.93	$	(25.49)	$	(24.99)	$	(22.09)

Table of Contents

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

Executive Overview

General

We are a petroleum company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas, onshore in the United States. We acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology to increase production, ultimate recoveries, or both.

We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain control of our assets for the benefit of our shareholders, including approximately 21.4% beneficially owned by our employees.

Our strategy is intended to generate scalable, low unit cost, development and re-development opportunities that minimize or eliminate exploration risks. These opportunities involve the application of modern technology, our own proprietary technology and our specific expertise in overlooked areas of the United States.

The assets we exploit currently fit into three types of project opportunities:

- Enhanced Oil Recovery (EOR),
- Bypassed Primary Resources, and
- Unconventional Development.

We expect to fund our base fiscal 2013 development plan from working capital, with any increases to the base plan funded out of working capital, net cash flows from our properties in the Giddings and Delhi Fields and appropriate financing vehicles, including possible additional issuances of our Series A perpetual non-convertible preferred stock.

Highlights for our fiscal year 2012

Oil & Gas Reserves

- **PV-10 of Proved reserves increased 19% to $446 million from last year s $375 million, despite a 3% decrease in volumes.** The increase in PV-10 (a non-GAAP measure reconciled to the GAAP measure below) was primarily due to higher average product prices realized during fiscal 2012. This was modestly offset by a 0.4 million BOE, or 3% decrease in proved reserve quantities due to 0.2 million BOEs of production and 0.2 million BOE in downward revisions net of additions. Positive revisions and additions in Delhi and Giddings were more than offset by negative revisions in Oklahoma and lease expiration of lower valued drilling locations in Giddings.

- **Proved Developed reserves increased 50% to 8.0 million BOE compared to 2011, or 60% of total proved volumes.** The increase in proved developed reserves is primarily due to the development of 2.6 million net BOE at our Delhi Field that was previously categorized as PUDs.

- **Our black oil volumes increased from 84% of proved reserves to 87% in 2012.**

- **PV-10 of Probable reserves increased 130% to $174 million, with a 104% increase in volumes to 12.7 million BOEs.** Most of the $99 million increase in PV-10, and virtually all of the 6.5 million BOE increase in probable reserves, was due to assignment of probable reserves to undeveloped leasehold in our Mississippi Lime project in North Central Oklahoma.

- **At yearend, we refocused our development activities on our Delhi, MS Lime and GARP projects going forward.** We believe expansion of these opportunities and others that we may add, combined with monetization or exit from our other projects, will optimize shareholder returns going forward.

Reserves MMBOE	13.4	13.8	(3)%	12.7	6.3	103%
% Developed	60%	39%	21%	21%	27%	(22)%
Liquids %	91%	89%	2%	78%	100%	(22)%
PV-10*	$ 445	$ 375	19%	$ 174	$ 76	129%
(In millions)						

Table of Contents

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* We believe the presentation of PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies and the relative monetary significance of their oil and natural gas properties. PV-10 is not intended to represent the current market value of our estimated oil and natural gas reserves, nor should it be considered in isolation or as a substitute for the Standardized Measure of after-tax discounted future net cash flows as defined under GAAP. See Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues under *Item 2. Properties* of this Form 10-K for a reconciliation of PV-10 to the Standardized Measure.

Projects

Delhi Field EOR Northeast Louisiana

As of June 30, 2012, D&M s independent reserve report for our Delhi interests continues to reflect a reversionary working interest payout date around late calendar 2013, accompanied by a 0.2 million BO increase in proved reserves. Based on this reversion date, we continue to expect to bear approximately $2.2 million of capital expenditures in calendar 2013 and $14.5 million in calendar 2014 to complete the development of proved reserves. Currently, all of our Delhi production comes from our 7.4% royalty interest that bears no cost or expense. At reversion, our net revenue interest will increase from 7.4% to 26.5%, and we will begin bearing 23.9% of all costs. We expect that the net cash flow from our combined revenue interest after reversion will more than amply cover the projected remaining capital expenditures.

Year-over-year, proved developed reserves at Delhi increased from 45% to 68% of Delhi proved reserves due to continued investment by the operator and performance in the field.

Annual production increased 208% year-over-year at Delhi from 121 net BO per day (1,633 gross BO per day) to 372 net BO per day (5,021 gross BO per day) as Phase II was fully reflected in production while Phase III installation was completed in the field. Sequentially, FQ4-2012 daily production sales declined 3% from 405 net BOD (5,474 gross) in FQ3-12 to 391 net BOD (5,274 gross).

The production decline at Delhi is a direct result of temporarily reduced injections of CO_2 due to plant turnaround, drilling activity and equipment limitations that were not related to reservoir issues. High ambient summer temperatures that were in excess of plant cooling capacity reduced the CO_2 injection capacity at the field that drives oil production, thus temporarily deferring a portion of oil production until cooler weather prevails. Looking forward, the operator expects to install additional cooling equipment prior to next summer that should eliminate this issue going forward. In addition, turnaround maintenance at the processing plant also temporarily impacted field production for a few days during the most recent quarter, and very active drilling operations in the field are believed to have impacted injection and production rates.

Currently, Phase IV installation is nearing completion. Up to six phases are ultimately expected for current proved reserves, with a seventh phase expected later this decade to add four similar reservoirs. To date, the operator has reported expending $479 million on the project. Our reversion, however, is based solely on our deemed $200 million reversionary payout amount. Our net production currently is from the 7.4% royalty interest and is free and clear of all cost, except for a pipeline transportation tariff of approximately $2.00 per barrel. Our realized oil price at Delhi tracks Louisiana Light Sweet oil price, which has been similarly tracking Brent crude oil price during 2012. As a result, our average realized price for the year at Delhi was $111 per barrel.

The impact of higher oil price on our expected reversion date of late calendar 2013 was offset by a more conservative slower ramp up of production forecast by our independent reservoir engineer in the June 30, 2012 report.

See Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues under *Item 2. Properties* of this Form 10-K for a reconciliation of PV-10 to the Standardized Measure.

Mississippi Lime North Central Oklahoma, Kay County

As previously announced, we believe the MS Lime fits well with our plans to redeploy near-term Delhi cash flows into one or more new development projects that are oil-focused, utilize our horizontal drilling expertise, have substantial room to

Table of Contents

expand, exhibit reasonable drilling and completion costs and are easily accessible and scalable. Accordingly, in April 2012, we entered the Mississippi Lime play in north central Oklahoma through a joint venture (JV) to acquire non-operating working interests from a private operator based in Tulsa, Oklahoma. Our position is in Kay County where the Mississippian Lime formation is well-defined by previous vertical development and historically has shown higher oil content.

At June 30, 2012, our independent reservoir engineers, Pinnacle Energy Services, LLC, assigned probable undeveloped reserves totaling 6.4 million BOE, net to our interest, with a PV-10 of $69 million. The estimated reserves are 57% black oil and 43% liquids rich natural gas. Our reserves are based on a current 5,405 net acres to our interest (being 45% of the JV) across 114 gross locations on 213 acre spacing, or three locations for each 640 acre section. On this basis, full development costs are estimated to be $73.5 million, net to our interest, or $11.44 per net BOE. We are developing the leasehold initially on 160 acre spacing based on current industry expectations.

With our JV partner, we collectively hold 11,878 net acres across 38 mostly contiguous sections averaging approximately 49% of the total gross acres. We expect to substantially increase our net acreage through forced pooling in these sections. We may also choose to acquire further bolt-on acreage, which would increase our capital requirements and potential reserves.

Our JV agreement requires us to drill three firm commitment wells, including one saltwater disposal well and two producer wells. As of this filing, all commitment wells have been drilled with the two producer wells waiting on hydraulic fracturing currently scheduled for September. Mississippian Lime wells typically require initial dewatering before significant oil and gas production is realized, and peak production rates may not be realized until several months after first production. At this time, we expect to monitor the production from the first two wells for several months before commencing a one drilling rig program.

GARP - Worldwide

During 2012, we entered into two commercialization agreements to install GARP in two wells in the Giddings Field. Both tests were completed with excellent results. In both wells, we were able to significantly increase production and reserves while substantially extending the economic lives and retaining leases.

Due to the success in both ventures, we are now in discussions to expand the application of GARP to larger groups of wells with the two partners and expect to use the success to enter into additional agreements.

Giddings Field Central Texas

Production declined 3% to 189 net BOE per day from 195 net BOE in fiscal 2011. Proved reserves declined 0.33 million BOE, excluding 69 MBOE of production. The slight decline in production was due to normal depletion partially offset by the addition of two commercial GARP demonstration wells we brought online with industry partners during fiscal 2012. Declines in proved reserves were due to expiring leases on three Giddings locations that we elected to not renew due to subpar economics driven by natural gas prices, consistent with our de-emphasis of Giddings. Accordingly, the PV-10 of proved reserves at Giddings declined 13% from $40.8 million in fiscal 2011 to $35.6 million at June 30, 2012.

Table of Contents

We continue to consider monetization of our Giddings assets not associated with our GARP business.

Lopez Field South Texas

We drilled and completed two producing wells and two salt water injection wells during 2012. Continued issues with inadequate injection rates led us to expend considerable, unexpected levels of operating expense during the year to develop improved injection capacity. During the third quarter, our efforts resulted in the first drilled producer consistently producing at an oil rate greater than expected on high fluid volumes. During the quarter ended June 30, 2012, the Lopez #5 averaged over 16 BO per day. The second drilled producer is waiting on new regulatory permits as log results convinced us to convert the drilled injection well with the drilled producer. Our independent reservoir engineer, W.D. Von Gonten, assigned 14 MBO of net proved reserves to the Lopez well based on limited production history, assigned 91.5 MBO of proved undeveloped reserves to six drilling locations and 475 MBO of probable reserves to 32 drilling locations.

Our interest in and development of the Lopez Field was based on the ability to prove the concept of redeveloping old oil fields with high water rates and extending that knowledge to similar fields in the region.

Operations

- **Fiscal 2012 net income was $4.5 million, a $4.7 million increase over fiscal 2011 s $0.2 million loss.**

- **Revenues in fiscal 2012 increased 139% to $18 million, compared to $7.5 million in fiscal 2011.** The revenue increase was due to a 79% BOE increase in sales volumes to 208 MBOE, aided by a 33% increase in realized prices averaging $86.29 per BOE. By far, Delhi was the largest contributor due to its 208% sales volume increase on a 9.3% increase in realized average prices to $111.29 per BO.

- **Operating costs in fiscal 2012 increased 24% to $9.1 million, while declining 28% on a BOE basis to $44 per BOE.** The key drivers to the $1.8 million increase in operating costs were a $0.4 million increase in lease operating expense due to work on water disposal issues at Lopez Field, a $0.6 million increase in depletion expense due to the 79% increase in production volumes, and a $0.8 million increase in G&A, largely due to higher incentive compensation, litigation and public reporting costs associated with becoming an accelerated filer.

- **Non-cash, stock-based compensation expense of $1.5 million comprised 24% of general and administrative expense for fiscal 2012.** Non-cash, stock-based compensation expense remains an important part of our total compensation program, as a small company in competition for talented staff with numerous, more established other companies, to help motivate and retain high performing employees and consultants, in addition to conserving our cash resources.

For further details, see Results of Operations below.

Finances

- **We ended the year with $11.7 million of working capital, compared to $4.1 million at June 30, 2011.** At June 30, 2012, working capital included $14.7 million of cash, cash equivalents and short-term certificates of deposit. The $7.6 million increase in our working capital since June 30, 2011 was due primarily to $10.4 million of net cash provided from operating activities, before changes in working capital, while the $6.6 million used in investing activities was virtually funded by the $6.4 million provided by financing activities.

- **Cash flows from operations covered our general and administrative expenses and all of our capital expenditures.** Cash flows from operations were $10.4 million during the year ended June 30, 2012.

- **In early July 2011, we added $6.9 million of liquidity through permanent equity via proceeds from sales of our Series A Preferred Stock.** We continue to believe this vehicle may provide us a vehicle for further anti-dilutive raises, as, if and when we need it and the markets are open.

- **We added an unsecured standby credit facility in the amount of $5 million, none of which has been drawn down as of the date of this filing.**

- **We remained debt free.** All of our expenditures were funded solely by working capital and we ended our fiscal year with no funded debt.

Table of Contents

Looking forward into 2013

We currently expect to be active during fiscal 2013 in the Mississippi Lime and through our GARP artificial lift technology, and funding our activity through existing working capital and internally generated cash flows from operations. We also are considering other projects meeting our strict criteria. These activities are intended to further our goal of maturing projects outside of Delhi and de-risking their future capital investment and associated production for near term value creation. At the same time, we expect production at Delhi to continue to increase as Phase III contributes to production and Phase IV is put into operation through incremental CO_2 injection.

Table of Contents

Our base case capital budget of $10 million will be primarily focused on:

- $8 million in the Mississippian Lime to complete our commitment wells and expand with 5-6 additional wells
- $1 million for initial projected GARP installations through current commercialization agreements
- $1 million for certain other projects
- Additional funding of other projects including Giddings, subject to non-monetization and commodity prices

We intend to generate and maintain substantial liquidity to allow us to take advantage of specific success in any one or more of the projects or other opportunities that may arise during the year due to unusual commodity price volatility or market disruption, including the possible repurchase of our common stock. We remain committed to protecting our substantial value already created in our Delhi assets and our conservative, flexible financial approach.

Continued conservative financial management.

- **Continue to emphasize long-term share value over near-term earnings during the current period of low natural gas prices.**

- **Retain financial strength and flexibility to assure we obtain proper value of our core assets and protect our joint venture rights in areas of mutual interest.**

- **Utilize joint ventures, project financing and/or preferred stock issuances to accelerate project development.** We may accelerate our development operations where warranted by utilizing joint ventures, project financing, selective divestments of noncore assets or continued issuance of our preferred stock at an attractive valuation.

- **Improve financial results through increasing production and revenues.**

Liquidity and Capital Resources

At June 30, 2012, our working capital was $11.7 million and we continued to be debt free. This compares to working capital of $4.1 million at June 30, 2011. The $7.6 million increase in working capital since June 30, 2011, was due primarily to $10.4 million of operating cash inflows as investing cash outflows were mostly offset by financing cash inflows reflecting the issuance of preferred stock during the current year. Of the $8.9 million of capital expenditures incurred during our fiscal year ended June 30, 2012, $5.6 million was for leasehold acquisitions and $3.3 million was for development activities. Development activities were primarily in the Lopez Field in Texas and Mississippian Lime project in Oklahoma. Capital expenditures were partially offset by sales of unproved leases in the amount of $0.8 million.

Cash Flows from Operating Activities

Cash flows provided by operating activities for the year ended June 30, 2012 were $10.4 million, reflecting $5.2 million of net income and $5.2 million provided by noncash expenses. Working capital items were essentially unchanged from the prior year. Included in noncash expenses were $1.2 million of depreciation, depletion and amortization; $1.5 million of stock-based compensation; and $2.5 million of deferred income taxes.

Cash flows provided by operating activities for the year ended June 30, 2011 were $3.1 million. Cash flows provided by operations included cash receipts of $7.0 million from oil and natural gas sales from our properties in the Giddings Field and the Delhi Field and $0.9 million due to a refund from the carry-back of our 2010 federal income tax loss. Cash payments included $4.5 million for operating expenses, including lease operating expenses, production taxes, salaries and wages, $0.1 million related to our joint interest partner s share of capital expenditures and which are due from our joint interest partner, and $0.2 million in estimated state income taxes.

Cash flows provided by operating activities for the year ended June 30, 2010 were $2.4 million. Cash flows provided by operations include cash receipts of $5.0 million from oil and natural gas sales, primarily from our properties in the Giddings Field, cash receipts of $2.1 million from the Internal Revenue Service due to our 2009 tax year net operating loss carry-back, and interest received of $0.1 million. Total cash received of $7.2 million was partially offset by $4.5 million of cash payments for operating expenses, including lease operating expenses, production taxes, salaries and wages, and payment of $0.3 million in state income taxes.

Table of Contents

Cash Flows from Investing Activities

Cash paid for oil and gas capital expenditures during the year ended June 30, 2012 was $7.0 million. Of these expenditures, $3.7 million was for leasehold acquisitions, principally in the Mississippi Lime in Oklahoma, and $3.3 million was for development activities. Development expenditures were primarily in the Lopez Field where four wells were drilled with remaining expenditures made in the Mississippi Lime and the Giddings Field in Texas.

Oil and gas capital expenditures incurred were $8.9 million for the year ended June 30, 2012. This amount can be reconciled to $7.0 million of cash capital expenditures on the cash flow statement by adjusting them for non-cash transactions, such as accrued capital expenditures presented at Note 9 Supplemental Cash Flow Information .

At June 30, 2012 the company had advanced $224,206 of cash for its share of development costs to be incurred by its joint venture partner in the Mississippian Lime play and recorded a $1,142,715 advance to be paid subsequent to June 30, 2012. This amount can be reconciled to cash advances to operator on the cash flow statement by adjusting for the related amount accrued as represented in the statement s supplemental information.

During the year ended June 30, 2012, we received $0.8 million for the sale of a portion of our Woodbine lease rights.

Cash paid for oil and gas capital expenditures during our fiscal year ended June 30, 2011was $3.5, which includes net payments on accounts payable of $0.1 million relating to expenditures for oil and natural gas properties. During the year ended June 30, 2011, we received $0.2 million for a lease sale in the Giddings Field.

During the year ended June 30, 2011, $1.1 million of certificates of deposit matured.

During the year ended June 30, 2010, we purchased $1.4 million in short-term certificates of deposit and $2.1 million of certificates of deposit matured.

Cash Flows from Financing Activities

During the year ended June 30, 2012, we received $6.9 million of net proceeds from the issuance of 317,319 shares of our 8.5% Series A perpetual preferred stock after all offering costs and we paid $0.6 million of dividends thereon. As a result of the unsecured revolving credit agreement entered into February 2012, the company incurred deferred loan costs of $163,257 during the current year. The facility, with availability of $5.0 million, is yet to be drawn upon. The company is in compliance with all covenants of the agreement.

During the year ended June 30, 2011, we received $0.1 million due to the exercise of stock options and $0.2 million for windfall tax benefit received in 2010.

There were no significant cash flows from financing activities during the year ended June 30, 2010.

Capital Budget

We expect to fund our fiscal 2013 Plan with internally generated funds, our working capital and future joint ventures. Increases in our activity level over the planned operations will be funded from working capital, joint ventures, project financing, selective divestments of noncore assets, from additional sales of our 8.5% Preferred Stock, or from borrowings under our revolving credit agreement.

Results of Operations

Year ended June 30, 2012 compared with the year ended June 30, 2011

The following table sets forth certain financial information with respect to our oil and natural gas operations:

	Year Ended June 30			
	2012	**2011**	**Variance**	**% change**
Sales Volumes, net to the Company:				
Delhi crude oil Royalty (Bbl)	136,074	44,141	91,933	208%
Other properties				
Crude oil (Bbl)	15,006	13,824	1,182	9%
NGLs (Bbl)	12,611	18,704	(6,093)	(33)%
Natural gas (Mcf)	266,787	238,608	28,179	12%
Crude oil, NGLs and natural gas (BOE)	208,156	116,437	91,719	79%
Revenue data:				
Delhi crude oil	$ 15,143,770	$ 4,493,240	$ 10,650,530	237%
Other properties				
Crude oil	1,403,645	1,179,231	224,414	19%
NGLs	620,187	893,525	(273,338)	(31)%
Natural gas	794,436	964,879	(170,443)	(18)%

Total revenues		17,962,038		7,530,875	$	10,431,163	139%
Average price:							
Delhi crude oil	$	111.29	$	101.79	$	9.50	9%
Other properties							
Crude oil (per Bbl)		93.54		85.30		8.24	10%
NGLs (per Bbl)		49.18		47.77		1.41	3%
Natural gas (per Mcf)		2.98		4.04		(1.06)	(26)%
Crude oil, NGLs and natural gas (per BOE)	$	86.29	$	64.68	$	21.61	33%
Expenses (per BOE)							
Lease operating expenses and production taxes	$	8.53	$	11.85	$	(3.32)	(28)%
Depletion expense on oil and natural gas properties (a)	$	5.22	$	4.55	$	0.67	15%

Table of Contents

(a) Excludes depreciation of office equipment, furniture and fixtures, and other asset amortization totaling $38,167 and $33,600, for the year ended June 30, 2012 and 2011, respectively. For the 2012 period only, other asset amortization of $11,787 is also excluded.

Net income (loss) attributable to common shareholders. For the year ended June 30, 2012, we reported a net income of $4,501,739 or $0.16 income per share (which includes $1,475,995 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $17,962,038. This compares to a loss $241,553, or $0.01 loss per share (which includes $1,536,007 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $7,530,875 for the year ended June 30, 2011. The difference was primarily due to an increase in crude oil revenues of $10,431,163 partially offset by $1,795,036 of increased operating expenses, higher income tax expense of $3,252,008 and preferred dividends of $630,391. Additional details of earnings components are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2012 increased 79% to 208,156 BOE, compared to 116,437 BOE for the year ended June 30, 2011.

Our crude oil sales volumes for the year ended June 30, 2012 included 136,074 Bbls of oil from Delhi, 13,160 Bbls of oil from our properties in the Giddings Field in Texas and 1,846 Bbls of oil from our South Texas properties. Our crude oil sales volumes for the year ended June 30, 2011 included 44,141 Bbls of oil from Delhi (of which 19,988 Bbls of oil were sold during the 4th quarter of 2011), 13,434 Bbls from the Giddings Field properties and 390 Bbls from the South Texas properties.

Entirely from our properties in the Giddings Field, our natural gas liquids production was 12,611 and 18,704 Bbls, respectively, for the years ended June 30, 2012 and 2011.

Natural gas production for the year ended June 30, 2012, included 5,840 Mcf from our properties in Oklahoma and 260,937 Mcf from our properties in the Giddings Field. For the year ended June 30, 2011, natural gas production included 3,757 Mcf from our properties in Oklahoma and 234,851 Mcf from our properties in the Giddings Field.

Petroleum Revenues. Total revenue increased 139% for the year ended June 30, 2012. This was due to volume increases of 161% for oil and 12% for natural gas, partially offset by a 33% decline in gas liquids production, and an increase in average price received per BOE, from $65 per BOE for the year ended June 30, 2011 to $86 per BOE for the year ended June 30, 2012.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes for the year ended June 30, 2012 increased 29% compared to the year ended June 30, 2011, reflecting costs associated with four wells drilled in the Lopez Field and workovers on two of its salt water disposal wells and 3 well bores acquired in the Giddings Fields. Lease operating expense and production taxes per barrel of oil equivalent decreased 28% from $11.85 per BOE during fiscal 2011, to $8.53 per BOE during fiscal 2012.

General and Administrative Expenses (G&A). G&A expenses increased 15% to $6.1 million for the year ended June 30, 2012, compared to $5.3 million for the year ended June 30, 2011. The increase primarily reflected higher accrued performance bonus, legal expenses, consulting services, employee pay rate adjustments and board fees. Non-cash stock-based compensation of $1,475,995 (24% of total G&A) and $1,536,007 (29% of total G&A) for the year ended June 30, 2012 and 2011, respectively, is an integral part of total staff compensation utilized to recruit quality staff from other, more established companies and, as a result, will likely continue to be a significant component of our G&A costs.

Depreciation, Depletion & Amortization Expense (DD&A). DD&A increased by 102% to $1,136,974 for year ended June 30, 2012, compared to $563,104 for the year ended June 30, 2011. The increase is primarily due to a 79% increase in net sales volumes, and a higher annual depletion rate ($5.22 vs. $4.55) per BOE. The higher depletion rate is due to our transfer of all remaining non-amortizing/unevaluated leasehold costs to our full cost pool during fiscal 2012, other than our Mississippi Lime acreage.

Year ended June 30, 2011 compared with the year ended June 30, 2010

The following table sets forth certain financial information with respect to our oil and natural gas operations:

	Year Ended June 30 2011	2010	Variance	% change
Sales Volumes, net to the Company:				
Delhi crude oil Royalty (Bbl)	44,141	6,333	37,808	597%
Other properties				
Crude oil (Bbl)	13,824	23,416	(9,592)	(41)%
NGLs (Bbl)	18,704	27,820	(9,116)	(33)%
Natural gas (Mcf)	238,608	407,674	(169,066)	(41)%
Crude oil, NGLs and natural gas (BOE)	116,437	125,515	(9,078)	(7)%
Revenue data:				
Delhi crude oil	$ 4,493,240	$ 485,032	$ 4,008,208	826%
Other properties				
Crude oil	1,179,231	1,703,227	(523,996)	(31)%
NGLs	893,525	1,079,383	(185,858)	(17)%

Natural gas		964,879		1,754,259		(789,380)	(45)%
Total revenues		7,530,875		5,021,901	$	2,508,974	50%
Average price:							
Delhi crude oil	$	101.79	$	76.59	$	25.20	33%
Other properties							
Crude oil (per Bbl)		85.30		72.74		12.56	17%
NGLs (per Bbl)		47.77		38.80		8.97	23%
Natural gas (per Mcf)		4.04		4.30		(0.26)	(6)%
Crude oil, NGLs and natural gas (per BOE)	$	64.68	$	40.01	$	24.67	62%
Expenses (per BOE)							
Lease operating expenses and production taxes	$	11.85	$	13.27	$	(1.42)	(11)%
Depletion expense on oil and natural gas properties (a)	$	4.55	$	14.10	$	(9.55)	(68)%

(a) Excludes depreciation of office equipment, furniture and fixtures, and other of $33,600 and $48,699, for the year ended June 30, 2011 and 2010, respectively.

<u>Net loss attributable to common shareholders</u> For the year ended June 30, 2011, we reported a net loss of $241,553, or $0.01 loss per share (which includes $1,536,007 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $7,530,875. This compares to a net loss of $2,387,707 or $0.09 loss per share (which includes $2,148,400 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $5,021,901 for the year ended June 30, 2010. The decrease in net loss was primarily

Table of Contents

due to an increase in our revenues of $2,508,974 and a decrease in operating costs of $1,298,758 (primarily related to a decrease in depreciation, depletion, and amortization). Additional details of the components of net loss are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2011 decreased 7% to 116,437 BOE, compared to 125,515 BOE for the year ended June 30, 2010.

Our crude oil sales volumes for the year ended June 30, 2011 included 44,141 Bbls of oil from Delhi, 13,434 Bbls of oil from our properties in the Giddings Field in Texas and 390 Bbls of oil from our South Texas properties. Our crude oil sales volumes for the year ended June 30, 2010 included 6,333 Bbls of oil from Delhi (of which 5,721 bbls of oil were sold during the 4th quarter of 2010) and 23,416 Bbls from our properties in the Giddings Field in Texas.

Our natural gas liquids production was entirely from our properties in the Giddings Field for the years ended June 30, 2011 and 2010.

Natural gas production for the year ended June 30, 2011, included 3,757 Mcfs from our properties in Oklahoma and 234,851 Mcfs from our properties in the Giddings Field. Natural gas production for the year ended June 30, 2010 was entirely from our properties in the Giddings Field.

Petroleum Revenues. Crude oil, NGLs and natural gas revenues for the year ended June 30, 2011 increased 50% from the year ended June 30, 2010. This was due to a 33% increase in liquid volumes, offset by a 41% decline in natural gas production, and a 62% increase in the average price received per BOE, from $40 per BOE for the year ended June 30, 2010 to $65 per BOE for the year ended June 30, 2011.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes for the year ended June 30, 2011 decreased 17% compared to the year ended June 30, 2010, primarily due to a significant reduction in saltwater disposal costs, due to our Pearson salt water disposal well, and decreased workover costs during the year ended June 30, 2011. Lease operating expense and production taxes per barrel of oil equivalent decreased 11% from $13.27 per BOE during fiscal 2010, to $11.85 per BOE during fiscal 2011.

General and Administrative Expenses (G&A). G&A expenses increased 5% to $5.3 million for the year ended June 30, 2011, compared to $5.1 million for the year ended June 30, 2010. The increase was due primarily to an increase in personnel costs of approximately $760 thousand offset by a reduction in stock-based compensation of approximately $600 thousand. We accrued for a cash bonus of $603 thousand for the year ended June 30, 2011, whereas in the prior year the bonus was paid in stock and accrued $587 thousand as stock-based compensation. The remaining increase in personnel costs were due to cost of living adjustments and a lower allocation of engineer costs to properties during the year ended June 30, 2011. Non-cash stock-based compensation of $1,536,007 (29% of total G&A) and $2,148,400 (42% of total G&A) for the year ended June 30, 2011 and 2010, respectively, is an integral part of total staff compensation utilized to recruit quality staff from other, more established companies and, as a result, will likely continue to be a significant component of our G&A costs.

Depreciation, Depletion & Amortization Expense (DD&A). DD&A decreased by 69% to $563,104 for year ended June 30, 2011, compared to $1,818,110 for the year ended June 30, 2010. The decrease is primarily due to a 7% decrease in net sales volumes, and a lower annual depletion rate ($4.55 vs. $14.10) per BOE. Our depletion rate decreased significantly in the fourth quarter of fiscal year 2010, when we first recorded reserves at Delhi of 9.4 million proved oil reserves with associated legacy costs of only $1.2 million transferred to our full cost pool.

Year ended June 30, 2010 compared with the year ended June 30, 2009

The following table sets forth certain financial information with respect to our oil and natural gas operations:

	Year Ended June 30 2010	2009	Variance	% change
Sales Volumes, net to the Company:				
Crude oil (Bbl)	29,749	36,026	(6,277)	(17)%
NGLs (Bbl)	27,820	44,125	(16,305)	(36)%
Natural gas (Mcf)	407,674	323,301	84,373	26%
Crude oil, NGLs and natural gas (BOE)	125,515	134,035	(8,520)	(6)%
Revenue data:				
Crude oil	$ 2,188,259	$ 2,747,494	$ (559,235)	(20)%
NGLs	1,079,383	1,625,063	(545,680)	(34)%
Natural gas	1,754,259	1,722,626	31,633	2%
Total revenues	5,021,901	$ 6,095,183	$ (1,073,282)	(18)%
Average price:				
Crude oil (per Bbl)	$ 73.56	$ 76.26	$ (2.70)	(4)%
NGLs (per Bbl)	38.80	36.83	1.97	5%
Natural gas (per Mcf)	4.30	5.33	(1.03)	(19)%
Crude oil, NGLs and natural gas (per BOE)	$ 40.01	$ 45.47	$ (5.46)	(12)%
Expenses (per BOE)				
Lease operating expenses and production taxes	$ 13.27	$ 10.69	$ 2.58	24%
Depletion expense on oil and natural gas properties (a)	$ 14.10	$ 18.07	$ (3.97)	(22)%

(a) Excludes depreciation of office equipment, furniture and fixtures, and other of $48,699 and $38,965, for the year ended June 30, 2010 and 2009, respectively.

Table of Contents

Net loss attributable to common shareholders. For the year ended June 30, 2010, we reported a net loss of $2,387,707, or $0.09 loss per share (which includes $2,148,400 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $5,021,901. This compares to a net loss of $2,601,593, or $0.10 loss per share (which includes $2,405,900 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $6,095,183 for the year ended June 30, 2009. A decrease in our revenues of $1,073,282 was offset by decreases in operating costs of $1,199,426 (primarily related to a decrease in G&A and depreciation, depletion, and amortization), and an increase in our income tax benefit of $154,960. Additional details of the components of net loss are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2010 decreased 6% to 125,515 BOE, compared to 134,035 BOE for the year ended June 30, 2009. Our sales volumes for the year ended June 30, 2010 included 6,333 Bbls of oil from Delhi (of which 5,721 bbls of oil were sold during the 4th quarter of 2010) and 119,182 BOE from our properties in the Giddings Field in Texas.

First EOR oil production at Delhi began in the last two weeks of March 2010. Total production from Delhi, net to our interest, for the year ended June 30, 2010 was 6,333 Bbls of oil compared to 172 Bbls of oil during the year ended June 30, 2009.

Production from our properties in the Giddings Field decreased 11% from 133,863 BOE during the fiscal year ended June 2009 to 119,182 BOE during the fiscal year ended June 30, 2010. Production of natural gas from our properties in the Giddings Field increased 26%, while production of crude oil and NGLs decreased 31% compared to the year ended June 30, 2009.

Petroleum Revenues. Crude oil, NGLs and natural gas revenues for the year ended June 30, 2010 decreased 18% from the year ended June 30, 2009. This was due to a 6% decline in sales volumes and a 12% decline in the average price received per BOE, from $45 per BOE for the year ended June 30, 2009 to $40 per BOE for the year ended June 30, 2010.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes for the year ended June 30, 2010 increased 16% compared to the year ended June 30, 2009, primarily due to the additions of three producing wells and an increase in workover expense from $232 thousand during fiscal 2009 to $452 thousand during fiscal 2010. Lease operating expense and production taxes per barrel of oil equivalent increased 24% from $10.69 per BOE during fiscal 2009, to $13.27 per BOE during fiscal 2010.

General and Administrative Expenses (G&A). G&A expenses decreased 14% to $5.1 million for the year ended June 30, 2010, compared to $5.9 million for the year ended June 30, 2009. The reduction was due to a decrease in non-cash stock-based compensation expense, which was $2,148,400 (42% of total G&A) and $2,405,900 (41% of total G&A) for the year ended June 30, 2010 and 2009, respectively, and a reduction of legal fees of approximately $380 thousand due to the settlement of the Delhi litigation in July 2009. Non-cash stock-based compensation is an integral part of total staff compensation utilized to recruit quality staff from other, more established companies and, as a result, will likely continue to be a significant component of our G&A costs.

Depreciation, Depletion & Amortization Expense (DD&A). DD&A decreased by 26% to $1,818,110 for year ended June 30, 2010, compared to $2,461,162 for the year ended June 30, 2009. The decrease is primarily due to a 6% decrease in net sales volumes, and a lower annual depletion rate ($14.10 vs. $18.07) per BOE. Our depletion rate for the fourth quarter of fiscal year 2010 was $4.39 per BOE compared to $17.23 for the 3rd quarter of 2010, due to the addition of 9.4 million proved oil reserves at Delhi with associated legacy costs of only $1.2 million transferred to our full cost pool. The lower fourth quarter rate is the primary cause of the lower annual depletion rate.

Inflation. Although the general inflation rate in the United States, as measured by the Consumer Price Index and the Producer Price Index, has been relatively low in recent years, the oil and gas industry has experienced unusually volatile price movements in commodity prices, vendor goods and oilfield services. Prices for drilling and oilfield services, oilfield equipment, tubulars, labor, expertise and other services greatly impact our lease operating expenses and our capital expenditures. During fiscal 2012, we saw modest increases in drilling and oilfield services costs over prior years. Product prices, operating costs and development costs may not always move in tandem.

Known Trends and Uncertainties. General worldwide economic conditions continue to be uncertain and volatile. Concerns over uncertain future economic growth are affecting numerous industries, companies, as well as consumers, which impact demand for crude oil and natural gas. If demand decreases in the future, it may put downward pressure on crude oil and natural gas prices, thereby lowering our revenues and working capital going forward. In addition, our lease operating expenses and their percentage of our revenues are likely to increase as our working interest production increases at our Mississippian Lime Play, reversion of our back-interest at Delhi or other additions to our working interest production that would dilute extraordinary margins we have enjoyed from our mineral and overriding royalty interests at Delhi.

Table of Contents

Seasonality. Our business is generally not directly seasonal, except for instances when weather conditions may adversely affect access to our properties or delivery of our petroleum products. Although we do not generally modify our production for changes in market demand, we do experience seasonality in the product prices we receive, driven by summer cooling and driving, winter heating, and extremes in seasonal weather including hurricanes that may substantially affect oil and natural gas production and imports.

Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2012, we are obligated to make under our contractual obligations and commitments. We expect to fund these contractual obligations with cash on hand and cash generated from operations.

	Payments Due by Period				
	Total	Less than 1 Year	2 3 Years	4 5 Years	After 5 Years
Contractual Obligations					
Operating lease	649,295	159,011	318,022	172,262	
Purchase commitment in connection with joint interest agreement	1,880,815	1,880,815			
Other Obligations					
Asset retirement obligations	968,677				968,677
Total obligations	$ 3,498,787	$ 2,039,826	$ 318,022	$ 172,262	$ 968,677

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires that we select certain accounting policies and make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. These policies, together with our estimates have a significant effect on our consolidated financial statements. Our significant accounting policies are included in Note 2 to the consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost accounting method for our oil and natural gas properties as prescribed by SEC Regulation S-X Rule 4-10. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. Costs are transferred to the full cost pool as the properties are evaluated. As of June 30, 2012, our total unevaluated costs were $6.0 million, all of which was associated with our Mississippi Lime leasehold position in North Central Oklahoma. If these costs were evaluated and included in our full cost pool, with no increases in our proved reserves as of June 30, 2012, our depreciation, depletion and amortization expense would have increased by approximately $24,000.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense, and the estimated future net cash flows associated with those proved reserves is the basis in determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, additional development activity, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare our reserve estimates, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and / or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves, affecting our quarterly ceiling test calculation and could significantly affect our depletion rate. A 10% decrease in commodity prices used to determine our proved reserves and Standardized Measure as of June 30, 2012, would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in the Company s proved reserve estimate at June 30, 2012 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $15,000, $31,000 and $49,000, respectively.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and gas reserves. The new rule allows consideration of new technologies in evaluating reserves, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and gas reserves using an average price based on the previous 12-month unweighted arithmetic average first-day-of-the-month price rather than year-end prices, revises the disclosure requirements for oil and gas operations, and revises accounting for the limitation on capitalized costs for full cost companies. The new rule became effective for our Annual Report on Form 10-K for the most recent fiscal year ended June 30, 2010 and did not have a material effect on our financial statements.

Valuation of Deferred Tax Assets. We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared or filed; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carry backs and carry forwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our net operating loss). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of June 30, 2012, we have recorded a valuation allowance for the portion of our net operating loss that is limited by IRS Section 382.

Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making the assessment of the ultimate realization of deferred tax assets. Based upon the level of historical taxable income and projections for future taxable income over the periods for which the deferred tax assets are deductible, as of end of the current fiscal year, we believe that it is more likely than not that the Company will realize the benefits of its net deferred tax assets. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not probable.

Stock-based Compensation. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option pricing model. This valuation method requires the input of certain assumptions, including expected stock price volatility, expected term of the award, the expected risk-free interest rate, and the expected dividend yield of the Company s stock. The risk-free interest rate used is the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. Our dividend yield is zero, as we do not pay a dividend. Because of our limited trading experience of our common stock and limited exercise history of our stock option awards, estimating the volatility and expected term is very subjective. We base our estimate of our expected future volatility, on peer companies whose common stock has been trading longer than ours, along with our own limited trading history while operating as an oil and natural gas producer. Future estimates of our stock volatility could be substantially different from our current estimate, which could significantly affect the amount of expense we recognize for our stock-based compensation awards.

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements as of June 30, 2012.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Commodity Price Risk

Our most significant market risk is the pricing for crude oil, natural gas and NGLs. We expect energy prices to remain volatile and unpredictable. If energy prices decline significantly, revenues and cash flow would significantly decline. In addition, a non-cash write-down of our oil and gas properties could be required under full cost accounting rules if future oil and gas commodity prices sustained a significant decline. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as, if and when needed. Although our current production base may not be sufficient enough to effectively allow hedging, we may use derivative instruments to hedge our commodity price risk.

Table of Contents

Item 8. Financial Statements

Index to Consolidated Financial Statements

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Evolution Petroleum Corporation

Houston, Texas

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2012 and 2011, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended June 30, 2012. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Evolution Petroleum Corporation and subsidiaries as of June 30, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2012, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Evolution Petroleum Corporation and subsidiaries internal control over financial reporting as of June 30, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated September 13, 2012 expressed an unqualified opinion on the effectiveness of Evolution Petroleum Corporation s internal control over financial reporting.

/s/ Hein & Associates LLP

Houston, Texas

September 13, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Evolution Petroleum Corporation

Houston, Texas

We have audited Evolution Petroleum Corporation s internal control over financial reporting as of June 30, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Evolution Petroleum Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (c) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Evolution Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of June 30, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2012 and 2011, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended June 30, 2012, and our report dated September 13, 2012, expressed an unqualified opinion.

/s/ Hein & Associates LLP

Houston, Texas

September 13, 2012

Table of Contents

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2012	June 30, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 14,428,548	$ 4,247,438
Certificates of deposit	250,000	250,000
Restricted cash from joint interest partner		118,194
Receivables		
Oil and natural gas sales	1,343,347	1,559,404
Joint interest partner	96,151	86,105
Income taxes	92,885	28,680
Other	190	167
Deferred tax asset	325,235	
Prepaid expenses and other current assets	233,433	67,852
Total current assets	16,769,789	6,357,840
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties full-cost method of accounting, of which $6,042,094 and $2,940,199 at June 30, 2012 and 2011, respectively, were excluded from amortization	40,476,172	33,447,564
Other property and equipment	92,271	69,262
Total property and equipment	40,568,443	33,516,826
Advances to joint interest operating partner	1,366,921	
Other assets	250,333	77,287
Total assets	$ 58,955,486	$ 39,951,953
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 407,570	$ 514,177
Due to joint interest partner	3,217,975	105,567
Accrued payroll	1,005,624	682,850
Royalties payable	294,013	742,651
State and federal taxes payable	91,967	82,122
Other current liabilities	71,768	84,565
Total current liabilities	5,088,917	2,211,932
Long term liabilities		
Deferred income taxes	6,205,093	3,330,266
Asset retirement obligations	968,677	859,586
Deferred rent	70,011	85,412
Total liabilities	12,332,698	6,487,196
Commitments and contingencies (Note 14)		
Stockholders equity		
Preferred stock, par value $0.001; 5,000,000 shares authorized: 8.5% Series A Cumulative Preferred Stock, 1,000,000 shares designated, 317,319 shares issued and outstanding at June 30, 2012, with a total liquidation preference of $7,932,975 ($25.00 per	317	

share)				
Common stock; par value $0.001; 100,000,000 shares authorized; issued 28,670,424 shares; outstanding 27,882,224 shares and 27,612,916 shares as of June 30, 2012 and 2011, respectively		28,670		28,400
Additional paid-in capital		29,416,914		20,761,209
Retained earnings		18,058,909		13,557,170
		47,504,810		34,346,779
Treasury stock, at cost, 788,200 shares as of June 30, 2012 and June 30, 2011		(882,022)		(882,022)
Total stockholders equity		46,622,788		33,464,757
Total liabilities and stockholders equity	$	58,955,486	$	39,951,953

See accompanying notes to consolidated financial statements.

Table of Contents

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Year Ended June 30, 2012	2011	2010
Revenues			
Crude oil	$ 16,547,415	$ 5,672,471	$ 2,188,259
Natural gas liquids	620,187	893,525	1,079,383
Natural gas	794,436	964,879	1,754,259
Total Revenues	17,962,038	7,530,875	5,021,901
Operating Costs			
Lease operating expenses	1,708,235	1,298,650	1,616,767
Production taxes	66,764	80,677	48,312
Depreciation, depletion and amortization	1,136,974	563,104	1,818,110
Accretion of asset retirement obligations	77,505	59,913	61,054
General and administrative expenses *	6,143,286	5,335,384	5,092,243
Total operating costs	9,132,764	7,337,728	8,636,486
Income (loss) from operations	8,829,274	193,147	(3,614,585)
Other			
Interest income	25,728	14,214	55,054
Interest (expense)	(21,950)		
Net income (loss) before income tax provision (benefit)	8,833,052	207,361	(3,559,531)
Income tax provision (benefit)	3,700,922	448,914	(1,171,824)
Net income (loss) attributable to the Company	5,132,130	(241,553)	(2,387,707)
Dividends on Preferred Stock	630,391		
Net income (loss) attributable to common shareholders	$ 4,501,739	$ (241,553)	$ (2,387,707)
Earnings (loss) per common share			
Basic	$ 0.16	$ (0.01)	$ (0.09)
Diluted	$ 0.14	$ (0.01)	$ (0.09)
Weighted average number of common shares outstanding			
Basic	27,784,298	27,437,496	27,004,066
Diluted	31,609,929	27,437,496	27,004,066

*General and administrative expenses for the year ended June 30, 2012, 2011 and 2010 included non-cash stock-based compensation expense of $1,475,995, $1,536,007 and $2,148,400, respectively.

See accompanying notes to consolidated financial statements.

Table of Contents

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flow

	Year Ended June 30, 2012	2011	2010
Cash Flows From Operating Activities			
Net income (loss) attributable to the Company	$ 5,132,130	$ (241,553)	$ (2,387,707)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,150,454	563,104	1,818,110
Stock-based compensation	1,475,995	1,536,007	2,148,400
Accretion of asset retirement obligations	77,505	59,913	61,054
Settlement of asset retirement obligations	(61,936)	(1,847)	
Deferred income taxes	2,549,592	380,386	(771,437)
Deferred rent	(15,401)	3,777	3,777
Other		32,080	5,717
Changes in operating assets and liabilities:			
Receivables from oil and natural gas sales	216,057	(1,023,038)	(4,048)
Receivables from income taxes and other	(64,194)	687,228	1,512,041
Due to/from joint interest partners	139,705	(87,743)	
Prepaid expenses and other current assets	(165,581)	90,652	3,947
Accounts payable and accrued expenses	379,873	497,783	65,144
Royalties payable	(448,638)	521,589	2,585
Income taxes payable	9,845	36,778	(112,402)
Net cash provided by operating activities	10,375,406	3,055,116	2,345,181
Cash Flows from Investing Activities			
Proceeds from asset sales	799,610	231,326	
Development of oil and natural gas properties	(3,291,921)	(2,509,652)	(3,280,425)
Acquisitions of oil and natural gas properties	(3,768,162)	(997,279)	(517,530)
Capital expenditures for other equipment	(61,176)	(864)	
Advances to joint venture operating partner	(224,206)		
Maturities of certificates of deposit		1,100,000	2,059,147
Purchases of certificates of deposit			(1,350,000)
Other assets	(35,056)	(48,702)	(13,220)
Net cash used in investing activities	(6,580,911)	(2,225,171)	(3,102,028)
Cash Flows from Financing Activities			
Proceeds from issuance of preferred stock, net	6,930,535		
Proceeds from issuance of restricted stock		28	42
Proceeds from the exercise of stock options		106,049	3,300
Preferred stock dividends paid	(630,391)		
Deferred loan costs	(163,257)		
Windfall tax benefit	249,728	173,157	
Net cash provided by financing activities	6,386,615	279,234	3,342
Net increase (decrease) in cash and cash equivalents	10,181,110	1,109,179	(753,505)
Cash and cash equivalents, beginning of period	4,247,438	3,138,259	3,891,764
Cash and cash equivalents, end of period	$ 14,428,548	$ 4,247,438	$ 3,138,259

See accompanying notes to consolidated financial statements.

Table of Contents

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity

For the Years ended June 30, 2012, 2011 and 2010

	Preferred Shares	Preferred Par Value	Common Stock Shares	Common Stock Par Value	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders Equity
Balance, July 1, 2009			26,530,317	$ 27,318	$ 16,424,868	$ 16,186,430	$ (882,022)	$ 31,756,594
Issuance of common stock to certain employees in lieu of cash payment of 2009 bonus			138,224	138	370,302			370,440
Issuance of restricted common stock			386,914	387	(345)			42
Exercise of stock warrants			133,005	133	(133)			
Exercise of stock options			3,000	3	3,297			3,300
Forfeiture of restricted common stock			(130,084)	(130)	130			
Windfall tax benefit					173,157			173,157
Stock-based compensation					1,561,367			1,561,367
Net loss						(2,387,707)		(2,387,707)
Balance, June 30, 2010			27,061,376	27,849	18,532,643	13,798,723	(882,022)	31,477,193
Issuance of common stock to certain employees in lieu of cash payment of 2010 bonus			106,927	107	586,926			587,033
Issuance of restricted common stock			303,603	303	(275)			28
Exercise of stock warrants			58,350	58	(58)			
Exercise of stock options			86,875	87	105,962			106,049
Forfeiture of restricted common stock			(4,215)	(4)	4			
Stock-based compensation					1,536,007			1,536,007
Net loss						(241,553)		(241,553)
Balance, June 30, 2011			27,612,916	28,400	20,761,209	13,557,170	(882,022)	33,464,757
Issuance of preferred stock	317,319	317			7,932,658			7,932,975
Preferred stock issuance costs					(1,002,440)			(1,002,440)
Issuance of restricted common stock			196,106	196	(162)			34
Exercise of stock warrants			65,261	66	(66)			
Exercise of stock options			7,941	8	(8)			
Stock-based compensation					1,475,995			1,475,995
Windfall tax benefit					249,728			249,728
Net income						5,132,130		5,132,130
Preferred Stock dividends						(630,391)		(630,391)
Balance, June 30, 2012	317,319	317	27,882,224	$ 28,670	$ 29,416,914	$ 18,058,909	$ (882,022)	$ 46,622,788

See accompanying notes to consolidated financial statements.

Table of Contents

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Basis of Preparation

Nature of Operations. Evolution Petroleum Corporation (EPM) and its subsidiaries (the Company , we , our or us), is an independent petrole company headquartered in Houston, Texas and incorporated under the laws of the State of Nevada. We are engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire properties with known oil and natural gas resources and exploit them through the application of conventional and specialized technology to increase production, ultimate recoveries, or both.

Principles of Consolidation and Reporting. Our consolidated financial statements include the accounts of EPM and its wholly-owned subsidiaries: NGS Sub Corp and its wholly owned subsidiary, Tertiaire Resources Company, NGS Technologies, Inc., Evolution Operating Co., Inc. and Evolution Petroleum OK, Inc. All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements for the previous year include certain reclassifications that were made to conform to the current presentation. Such reclassifications have no impact on previously reported income or stockholders equity.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant estimates include reserve quantities and estimated future cash flows associated with proved reserves, which significantly impact depletion expense and potential impairments of oil and natural gas properties, income taxes and the valuation of deferred tax assets, stock-based compensation and commitments and contingencies. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Note 2 Summary of Significant Accounting Policies

Cash and Cash Equivalents. We consider all highly liquid investments, with original maturities of 90 days or less when purchased, to be cash and cash equivalents.

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivables if it is determined that collection of all or a part of an outstanding balance is not probable. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2012 and 2011, no allowance for doubtful accounts was considered necessary.

Oil and Natural Gas Properties. We use the full cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Excluded costs represent investments in unproved and unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the project is evaluated and proved reserves are established or impairment is determined. Excluded costs are reviewed at least quarterly to determine if impairment has occurred. The amount of any evaluated or impaired oil and natural gas properties is transferred to capitalized costs being amortized (the Full-cost Pool).

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the Ceiling Test). If the capitalized cost of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes (the Net Capitalized Costs), exceed the Ceiling , this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent, and assuming continuation of existing economic conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices determined as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period (with consideration of price

Table of Contents

changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. Our Ceiling Test did not result in an impairment of our oil and natural gas properties during the years ended June 30, 2012, 2011 and 2010, or any other year since our inception.

Other Property and Equipment. Other property and equipment includes buildings, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets, which ranges from three to seven years. Repairs and maintenance costs are expensed in the period incurred.

Deferred Costs

The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in Deferred costs and other assets on the Company s Consolidated Balance Sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

Asset Retirement Obligations. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred, with an associated increase in the carrying amount of the related long-lived asset, our oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset which is considered a level 3 fair value measurement. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, certificates of deposit, accounts receivable, and accounts payable. The carrying amounts of these approximate fair value, due to the highly liquid nature of these short-term instruments.

Stock-based Compensation. We record all share-based payment expense in our financial statements based on the fair value of the award on the grant date. We use the Black-Scholes option-pricing model as the most appropriate fair-value method for our stock option awards. Restricted stock awards are valued using the market price of our common stock on the grant date. We record compensation cost, net of estimated forfeitures, for stock-based compensation awards over the requisite service period on a straight-line basis as the awards vest. As each award vests, an adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the vested awards.

Revenue Recognition. We recognize oil and natural gas revenue from our interests in producing wells at the time that title passes to the purchaser. As a result, we accrue revenues related to production sold for which we have not received payment.

Depreciation, Depletion and Amortization. The depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of DD&A, estimated future development costs and asset retirement costs not included in oil and natural gas properties, less costs excluded from amortization. The depreciable base of oil and natural gas properties is amortized using the unit-of-production method. Other property including, leasehold improvements, office and computer equipment and vehicles which are stated at original cost and depreciated using the straight-line method over the useful life of the assets, which ranges from three to seven years.

Income Taxes. We recognize deferred tax assets and liabilities based on the differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that may result in taxable or deductible amounts in future years. The measurement of deferred tax assets may be reduced by a valuation allowance based upon management s assessment of available evidence if it is deemed more likely than not some or all of the deferred tax assets will not be realizable. We recognize a tax benefit from an uncertain position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position and will record the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement with a taxing authority.

Earnings (loss) per share. Basic Earnings (loss) per share (EPS) is computed by dividing earnings or loss by the weighted-average number of common shares outstanding less any non-vested restricted common stock outstanding. The computation of diluted EPS is similar to the computation of basic EPS, except that the denominator is increased to include the number of additional common shares that would have been outstanding if potential dilutive common shares had been issued. Our potential dilutive common shares are our

Table of Contents

outstanding stock options, warrants, and non-vested restricted common stock. The dilutive effect of our potential dilutive common shares is reflected in diluted EPS by application of the treasury stock method. Under the treasury stock method, exercise of stock options and warrants shall be assumed at the beginning of the period (or at time of issuance, if later) and common shares shall be assumed to be issued; the proceeds from exercise shall be assumed to be used to purchase common stock at the average market price during the period; and the incremental shares (the difference between the number of shares assumed issued and the number of shares assumed purchased) shall be included in the denominator of the diluted EPS computation. Potential dilutive common shares are excluded from the computation if their effect is anti-dilutive. Including potential dilutive common shares in the denominator of a diluted EPS computation for continuing operations always will result in an anti-dilutive per-share amount when an entity has a loss from continuing operations and no potential dilutive common shares shall be included in the computation of diluted EPS when a loss from continuing operations exists.

Note 3 Recent Accounting Pronouncements

New Accounting Standards. We disclose the existence and potential effect of accounting standards issued but not yet adopted by us or recently adopted by us with respect to accounting standards that may have an impact on us in the future.

Fair Value. In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 changes some fair value measurement principles under GAAP, including a change in the valuation premise and the application of premiums and discounts. It also contains some new disclosure requirements under GAAP. It is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this new guidance to have a significant impact on its financial position, cash flows or results of operations.

Offsetting Assets and Liabilities. In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11), which requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. ASU 2011-11 is effective for interim and annual periods beginning on or after January 1, 2013. The Company does not expect the adoption of this new guidance to have any impact on its financial position, cash flows or results of operations.

Note 4 Property and Equipment

As of June 30, 2012 and June 30, 2011 our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2012	June 30, 2011
Oil and natural gas properties		
Property costs subject to amortization	$ 40,874,244	$ 35,860,517
Less: Accumulated depreciation, depletion, and amortization	(6,440,166)	(5,353,152)
Unproved properties not subject to amortization	6,042,094	2,940,199

Oil and natural gas properties, net	$	40,476,172	$	33,447,564
Other property and equipment				
Furniture, fixtures and office equipment, at cost	$	322,514	$	261,340
Less: Accumulated depreciation		(230,243)		(192,078)
Other property and equipment, net	$	92,271	$	69,262

Unproved properties not subject to amortization includes unevaluated acreage of $6.0 and $2.2 million as of June 30, 2012 and June 30, 2011, respectively, consisting of properties in the Mississippi Lime in Oklahoma as of June 30, 2012 and in the Woodford Shale trend in Oklahoma as of June 30, 2011. Unproved properties include $0.7million as of June 30, 2011 of participating interests through royalty and overriding royalty interests aggregating 7.4% in the Delhi Holt Bryant Unit of the Delhi Field in Louisiana and a 23.9% after payout reversionary working interest in the Delhi Holt Bryant Unit along with a 23.9% working interest in certain other depths in the Delhi Field. Our evaluation of impairment of unproved properties occurs, at a minimum, on a quarterly basis.

The following table provides a summary of costs that are not being amortized as of June 30, 2012, by the fiscal year in which the costs were incurred:

Table of Contents

Costs excluded from amortization	Total	2012	During the Year Ended June 30, 2011	2010	2009	2008
Leasehold acquisition costs and other	$ 6,042,094	$ 6,042,094	$	$	$	$

During the year, the Company received proceeds totaling $799,610, and the retention of overrides and back-in interests, for the farmout of some of its Woodbine rights at Giddings.

Note 5 Joint Interest Agreement

Effective April 17, 2012, a wholly owned subsidiary of the Company entered into definitive agreements with Orion Exploration Partners, LLC (Orion) to acquire and develop an undivided 45% interest in oil and gas leases, associated surface rights and related assets located in the Mississippian Lime formation aggregating 11,700 acres (5,265 net acres) in 38 sections in Kay County in North Central Oklahoma. The Company has agreed to contribute cash and a drilling carry to maintain its 45% non-operating interest in the joint venture. Orion is contributing the leases, its portion of the drilling capital, its operating expertise in the area and the Mississippian Lime play. The agreement commits the parties to drill between six and fourteen gross wells by April 17, 2013.

In April we made our initial $4,083,780 cash outlay for the purchase of our 45% share of the JV leasehold and partial prepayment of our drilling and completion costs of the first three commitment wells. Our acquisition cost also includes carrying our partner for a portion of their drilling and completion costs over the next year, not to exceed approximately $2.2 million, which is subject to a security agreement.

Field operations began in May 2012 with the drilling of a water disposal well, followed by the drilling of two producer wells with the first commencing in June 2012 and the second commencing in July 2012.

Our participation in this joint venture is reflected on our June 30, 2012 balance sheet by the items below. Included in the $1.4 million advance to our joint interest operating partner is an accrued $1,142,716 drilling cash call, which is also reflected in the due to joint interest partner balance.

	June 30, 2012
Advances to joint interest operating partner	$ 1,366,921
Due to joint interest partner	3,217,975

Note 6 Asset Retirement Obligations

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following is a reconciliation of the beginning and ending asset retirement obligation for the years ended June 30, 2012 and 2011:

Table of Contents

	Year Ended			
		2012		2011
Asset retirement obligations beginning of period	$	859,586	$	811,635
Liabilities incurred		175,943		15,000
Liabilities settled		(61,936)		(1,847)
Accretion		77,505		59,913
Revisions to previous estimates		(82,421)		(25,115)
Asset retirement obligations end of period	$	968,677	$	859,586

Note 7 Stockholders Equity

Common Stock

On September 8, 2009, the Board of Directors authorized and the Company issued 138,224 unrestricted and fully vested shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2009 bonuses. The value of the shares issued was $370,440, based on the fair market value on the date of issuance, or $2.68 per share. The amount of bonus was accrued as of June 30, 2009 and recognized as a long-term liability. On September 8, 2009, when the shares were issued, the liability was reclassified to stockholders equity. See Note 8.

On September 8, 2009, the Board of Directors authorized and the Company issued 324,597 shares of restricted common stock from the 2004 Stock Plan to employees as a long-term incentive award. Total unrecognized stock-based compensation expense of $869,917 related to the long-term incentive award will be recognized ratably over a four year vesting period. See Note 8.

On October 27, 2009, 119,795 shares of common stock were issued through a net cashless exercise of a placement warrant. The placement warrant, which was issued to Cagan McAfee Capital Partners, LLC (CMCP), a related party (See Note 11), on May 26, 2004 in connection with a financing transaction, gave CMCP the right to purchase 165,000 shares, with an exercise price of $1.00 per share.

On November 10, 2009, 5,833 shares of common stock were issued through a net cashless exercise of a placement warrant. The placement warrant, issued on November 30, 2004 in connection with a financing transaction, gave the holder the right to purchase 10,000 shares, with an exercise price of $1.50 per share.

On December 9, 2009, a total of 42,317 shares of restricted common stock were issued to four outside directors as part of their board compensation for calendar year 2010. The value of the shares issued was $168,000, based on the fair market value on the date of issuance. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors. See Note 8.

On February 6, 2010, a total of 38,182 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $187,965. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 8.

On March 5, 2010, a total of 20,000 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $90,000, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 8.

On April 14, 2010 and April 16, 2010, a total of 7,377 shares of common stock were issued through a net cashless exercise of a placement warrant. The placement warrants, issued on June 22, 2006 in connection with a financing transaction, gave the holder the right to purchase 12,000 shares, with an exercise price of $2.25 per share.

On June 14, 2010, an employee of the Company exercised 3,000 stock options granted in 2005 at an exercise price of $1.10. See Note 8.

On June 19, 2010, a total of 91,902 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $436,522. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 8.

On July 2, 2010, an employee of the Company exercised 6,875 stock options granted in 2007 at an exercise price of $2.33 per share. See Note 8.

On July 2, 2010, a total of 4,215 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $11,621. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 8.

On August 9, 2010, a total of 30,233 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $156,000, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 8.

On September 10, 2010, the Board of Directors authorized and the Company issued 106,927 shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2010 bonuses. The value of the shares issued were $587,033, based on the fair market value on the date of issuance, or $5.49 per share. The amount of bonus was accrued as of June 30, 2010, and recognized as a long term liability. On September 10, 2010, the date of the share issuance, the liability was reclassified to additional paid-in capital.

On September 10, 2010, the Board of Directors authorized and the Company issued 240,478 shares of restricted common stock from the 2004 Stock Plan to certain employees as a long-term incentive award. Total unrecognized stock-based compensation expense of $1,320,224 related to the long-term incentive award will be recognized ratably over a four year period as the restricted common stock vests. See Note 8.

On October 1, 2010, a total of 4,845 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $29,118, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 8.

On December 9, 2010, a total of 28,047 shares of restricted common stock was issued to four outside directors as part of their board compensation for calendar year 2011. The value of the shares issued was $168,000, based on the fair market value on the date of issuance. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors. See Note 8

On December 21, 2010, an employee of the Company exercised 30,000 stock options granted in 2003 at an exercise price of $0.001 per share. See Note 8.

On February 28, 2011, a former consultant of the Company exercised 50,000 stock options granted in 2005 at an exercise price of $1.80 per share. See Note 8.

On March 31, 2011, 58,350 shares of common stock were issued through a net cashless exercise of placement warrants. The placement warrants, which were issued to Laird Cagan, a related party (See Note 11), in 2004 in connection with a financing transaction, gave Mr. Cagan the right to purchase 66,943 shares, with a weighted average exercise price of $1.00 per share.

On September 9, 2011, a contractor of the Company net exercised 20,000 stock options issued under the 2004 Stock Plan for a net issuance of 7,941 shares of our common stock. The options were granted in March 2008 at an exercise price of $4.10 per share. See Note 8.

On August 31, 2011, the Board of Directors authorized the issuance of 161,861 shares of restricted common stock from the 2004 Stock Plan to all employees as a long-term incentive award. Total unrecognized stock-based compensation expense of $1,029,436 related to the long-term incentive award will be recognized ratably over a four year period as, if and when the restricted common stock vests. See Note 8.

On December 5, 2011, a total of 34,245 shares of our restricted common stock were issued pursuant to the 2004 Stock Plan to five outside directors as part of their annual board compensation for calendar year 2012. The value of the shares issued was $249,955, based on the fair market value on the date of issuance. All issuances of our common stock were subject to vesting terms per individual stock agreements, which is one year for directors. See Note 8.

On May 3, 2012, we issued Laird Cagan 65,261 shares of common stock through a net cashless exercise of a placement warrant. On May 6, 2005, in connection with a financing transaction, the Company issued the placement warrant to Mr. Cagan, a related party (see Note 11), that gave him the right to purchase 91,200 shares of common stock with an exercise price of $2.50 per share.

Table of Contents

Series A Cumulative Perpetual Preferred Stock

During the year ended June 30, 2012, we sold 317,319 shares of our 8.5% Series A Cumulative (perpetual) Preferred Stock at a weighted average sales price of $23.80 per share, with a liquidation preference of $25.00 per share. All shares were underwritten or sold through McNicoll Lewis & Vlak LLC (MLV), 220,000 of which were sold in an underwritten public offering and 97,319 shares of which were sold under an at-the-market sales agreement (ATM), providing aggregate net proceeds of $6,930,535 after- market discounts, underwriting fees, legal and other expenses of the offerings. The Series A Cumulative Preferred Stock cannot be converted into our common stock and there are no sinking fund or redemption rights available to holders thereof. Optional redemption can only be made by us on or after July 1, 2014 for the stated liquidation value of $25.00 per share plus accrued dividends, or by an acquirer under a change of control prior to such date at redemption prices ranging from $25.25 to $25.75 per share. With respect to dividend rights and rights upon our liquidation, winding-up or dissolution, the Series A Preferred Stock ranks senior to our common shareholders, but subordinate to any of our existing and future debt. Dividends on the Series A Cumulative Preferred Stock accrue and accumulate at a fixed rate of 8.5% per annum on the $25.00 per share liquidation preference, payable monthly at $0.177083 per share, as, if and when declared by our Board of Directors.

During the year ended June 30, 2012, we paid dividends of $630,391 to holders of our Series A Preferred Stock.

Note 8 Stock-Based Incentive Plan

We have granted option awards to purchase common stock (the Stock Options), restricted common stock awards (Restricted Stock), and/or unrestricted fully vested common stock, to employees, directors, and consultants of the Company and its subsidiaries under the Natural Gas Systems Inc. 2003 Stock Plan (the 2003 Stock Plan) and the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the 2004 Stock Plan or together, the EPM Stock Plans). Option awards for the purchase of 600,000 shares of common stock were issued under the 2003 Stock Plan. The 2004 Stock Plan authorized the issuance of 6,500,000 shares of common stock. No shares are available for grant under the 2003 Stock Plan and 1,012,111 shares remain available for grant under the 2004 Stock Plan as of June 30, 2012.

We have also granted common stock warrants, as authorized by the Board of Directors, to employees in lieu of cash bonuses or as incentive awards to reward previous service or provide incentives to individuals to acquire a proprietary interest in the Company s success and to remain in the service of the Company (the Incentive Warrants). These Incentive Warrants have similar characteristics of the Stock Options. A total of 1,037,500 Incentive Warrants have been issued, with Board of Directors approval, outside of the EPM Stock Plans. We have not issued Incentive Warrants since the listing of our shares on the NYSE MKT (formerly, the American Stock Exchange) in July 2006.

Short-term Incentive Compensation

On September 10, 2010, the Board of Directors authorized the issuance of 106,927 shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2010 bonuses in lieu of cash. The value of the shares issued was $587,033, based on the fair market value on the date of issuance, or $5.49 per share. The amount of bonus was accrued as of June 30, 2010, and recognized as a long term liability. On September 10, 2010, the liability was reclassified as additional paid-in capital.

Stock Options and Incentive Warrants

Non-cash stock-based compensation expense related to Stock Options and Incentive Warrants for the years ended June 30, 2012, 2011 and 2010 was $327,776, $715,027and $985,060, respectively.

There were no Stock Options granted during the years ended June 30, 2012, 2011 and 2010. During the year ended June 30, 2009, we granted Stock Options to purchase 591,090 shares of common stock under the 2004 Stock Plan with a weighted average exercise price of $4.27. The exercise price was determined based on the market price of the Company s common stock on the date of grant. The Stock Options granted during the years ended June 30, 2009 generally vest quarterly, on a straight line basis, over a period of four years. The Stock Options granted during the year ended June 30, 2009 have a contractual life of seven years. The weighted average assumptions used to calculate the fair value of these Stock Options and the weighted average fair value of each option granted are as follows:

Table of Contents

Expected volatility		87.1%
Expected dividends		
Expected term (in years)		4.6
Risk-free rate		3.10%
Fair value	$	2.62

We estimated the fair value of Stock Options and Incentive Warrants issued to employees and directors at the date of grant using a Black-Scholes-Merton valuation model. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The expected term (estimated period of time outstanding) of Stock Options and Incentive Warrants is based on the simplified method of the estimated expected term for plain vanilla options allowed by the SEC Staff Accounting Bulletin (SAB) No. 107 and SAB No. 110, and varied based on the vesting period and contractual term of the Stock Options or Incentive Warrants. Expected volatility is based on the historical volatility of the Company s closing common stock price and that of an evaluation of a peer group of similar companies trading activity. We have not declared any cash dividends on the Company s common stock.

The following summary presents information regarding outstanding Stock Options and Incentive Warrants as of June 30, 2012, and the changes during the fiscal year:

	Number of Stock Options and Incentive Warrants		Weighted Average Exercise Price		Aggregate Intrinsic Value (1)	Weighted Average Remaining Contractual Term (in years)
Stock Options and Incentive Warrants outstanding at July 1, 2011	5,392,820	$	1.85			
Granted						
Exercised	(20,000)	$	4.10			
Cancelled or forfeited						
Expired						
Stock Options and Incentive Warrants outstanding at June 30, 2012	5,372,820	$	1.83	$	34,957,022	3.4
Vested or expected to vest at June 30, 2012	5,372,820	$	1.83	$	34,957,022	3.4
Exercisable at June 30, 2012	5,353,898	$	1.83	$	34,875,456	3.4

(1) Based upon the difference between the market price of our common stock on the last trading date of the period ($8.34 as of June 30, 2012) and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

For the year ended June 30, 2012, 20,000 Stock Options were exercised having an aggregate intrinsic value of $54,000. There were 86,875 Stock Options exercised during the year ended June 30, 2011 with an aggregate intrinsic value of $493,923. There were 3,000 Stock Options exercised during the year ended June 30, 2010 with an aggregate intrinsic value of $13,620.

Table of Contents

A summary of the status of our unvested Stock Options and Incentive Warrants as of June 30, 2012 and the changes during that year ended are presented below:

	Number of Stock Options and Incentive Warrants	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2011	173,877	$ 2.20
Granted		
Vested	(154,955)	$ 2.17
Unvested at June 30, 2012	18,922	$ 2.45

During the years ended June 30, 2012, June 30, 2011 and 2010, there were 154,955, 375,580, and 539,330 Stock Options and Incentive Warrants that vested with a total grant date fair value of $336,252, $739,893, and $1,024,727, respectively.

The total unrecognized compensation cost at June 30, 2012, relating to non-vested Stock Options and Incentive Warrants was $26,273. Such unrecognized expense is expected to be recognized over a weighted average remaining service period of 0.25 years.

Restricted Stock

Stock-based compensation expense related to Restricted Stock grants for the years ended June 30, 2012, 2011 and 2010 was $1,148,219, $820,980, and $576,307, respectively. See Note 7 for a detail of Restricted Stock transactions during the years ended June 30, 2012, 2011 and 2010.

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2012:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2011	495,689	$ 4.30
Granted	196,106	$ 6.52
Vested	(239,195)	$ 4.51

Unvested at June 30, 2012	452,600	$ 5.60

During the years ended June 30, 2012, June 30, 2011 and 2010, there were 239,195, 206,858, and 243,954 shares of Restricted Stock that vested with a total grant date fair value of $1,078,769, $794,335, and $551,336, respectively.

At June 30, 2012, unrecognized stock compensation expense related to Restricted Stock grants totaled $2,118,741. Such unrecognized expense will be recognized over a weighted average remaining service period of 2.3 years.

Table of Contents

Note 9 Supplemental Disclosure of Cash Flow Information

Our supplemental disclosures of cash flow information for the year ended June 30, 2012, 2011 and 2010 are as follows:

	Year Ended June 30, 2012		2011		2010	
Income taxes paid	$	895,000	$	229,802	$	329,800
Income tax refunds and net operating loss carry-back received	$		$	979,177	$	2,095,126
Non-cash transactions:						
Change in accounts payable used to acquire oil and natural gas leasehold interests and develop oil and natural gas properties	$	(196,396)	$	(91,483)	$	(62,532)
Change in due to joint venture partner used to acquire oil and natural gas leasehold interests and develop oil and natural gas properties	$	1,958,029	$		$	
Accrued advance in due to joint venture partner	$	1,142,715	$		$	
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	$	93,522	$	15,000	$	85,871
Windfall tax benefit recognized in income taxes recoverable	$		$		$	173,157

Note 10 Income Taxes

We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions.

There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits during the year ended June 30, 2012, 2011 and 2010. We believe that we have appropriate support for the income tax positions taken and to be taken on the Company s tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company s tax returns are open to audit under the statute of limitations for the years ending June 30, 2008 through June 30, 2011 for federal tax purposes and for the years ended June 30, 2008 through June 30, 2011 for state tax purposes.

As a result of our net operating losses during the tax years ended June 30, 2010, 2009, and 2008, and the refunds we claimed as a result of our carry backs of those losses to our tax years ended June 30, 2006 and 2007, we are under a limited scope IRS audit. The IRS limited scope audit is pending joint committee review. We do not expect that the limited scope audit will have a significant effect on our financial condition and results of operations.

The components of our income tax provision (benefit) are as follows:

	June 30, 2012	June 30, 2011	June 30, 2010
Current:			
Federal	$ 309,632	$ (64,068)	$ (608,339)
State	841,698	132,596	207,952
Total current income tax provision (benefit)	1,151,330	68,528	(400,387)
Deferred:			
Federal	2,542,662	360,174	(553,326)
State	6,930	20,212	(218,111)
Total deferred income tax provision (benefit)	2,549,592	380,386	(771,437)
Total income tax provision (benefit)	$ 3,700,922	$ 448,914	$ (1,171,824)

Table of Contents

The 2012 effective tax rate is in excess of the federal statutory rate primarily due to the incentive based stock compensation and increased Louisiana state income tax (due to the increased Delhi revenue). The 2011 effective rate is well in excess of the federal statutory rate primarily due to the reversal of permanent deductions take in prior years that were recomputed as a result of the federal NOL carryback claims as well as incentive based stock compensation. The rate appears abnormally high as a result of the fixed dollar nature of the permanent items in relation to the nearly breakeven pretax book income. The 2010 effective tax rate is slightly below the federal statutory rate primarily due to a pretax book loss offset by a permanent addition for incentive based stock compensation. The following is a reconciliation of statutory income tax expense to our income tax provision (benefit):

	June 30, 2012	June 30, 2011	June 30, 2010
Income tax provision (benefit) computed at the statutory federal rate:	$ 3,003,238	$ 70,503	$ (1,210,241)
Reconciling items:			
State income taxes, net of federal tax benefit	560,095	100,853	(10,413)
Stock-based compensation (primarily incentive stock options)	83,115	140,620	105,402
Expiring NOLs related to 2004 reverse merger	4,348,495		
Deferred tax asset valuation adjustment	(4,348,495)		
Reversal of Section 199 deductions as a result of carry-backs		141,920	
Rate adjustment		(7,172)	(42,651)
Other	54,474	2,190	(13,921)
Income tax provision (benefit)	$ 3,700,922	$ 448,914	$ (1,171,824)

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Deferred tax assets and liabilities are classified as either current or noncurrent on the balance sheet based on the classification of the related asset or liability for financial reporting purposes. Deferred tax assets and liabilities not related to specific assets or liabilities on the financial statements are classified according the expected reversal date of the temporary difference or the expected utilization date for tax attribute carryforwards. The change in the NOL is primarily due to expiring NOLs related to the 2004 reverse merger as well as utilization of NOL to offset potential current year taxable income. The components of our deferred taxes are detailed in the table below:

	June 30, 2012	June 30, 2011	June 30, 2010
Deferred tax assets:			
Non-qualified stock-based compensation	$ 774,720	$ 959,547	$ 866,035
Net operating loss carry-forwards**	1,336,769	5,910,275	5,389,065
AMT credit carry-forward*	714,571	682,456	645,938
Other	29,929	23,626	21,306
Gross deferred tax assets	2,855,989	7,575,904	6,922,344
Valuation allowance	(893,410)	(5,187,983)	(5,187,983)
Total deferred tax assets	1,962,579	2,387,921	1,734,361
Deferred tax liability:			
Oil and natural gas properties	(7,842,437)	(5,718,187)	(4,684,241)
Total deferred tax liability	(7,842,437)	(5,718,187)	(4,684,241)
Net deferred tax liability	$ (5,879,858)	$ (3,330,266)	$ (2,949,880)

* Total AMT credit carry-forward is $844,440. Our net deferred tax liability does not include $129,869 of AMT credit carry-forward associated with the windfall tax benefit.

** Excluded from our net tax liability is an estimated tax benefit of $394,487 related to net operating losses associated windfall tax benefits.

We recovered approximately $1.0 million in federal income taxes as a result of the carry-back of tax losses incurred during June 30, 2010. The loss carry-back was primarily the result of significant intangible drilling costs incurred during that year, which we deducted for federal income tax purposes.

At June 30, 2012, we have a federal tax loss carry-forward of approximately $3.9 million, exclusive of the $1.1 million non-benefitted NOL related to unutilized windfall tax benefits. Included in the deferral tax loss carry-forward is approximately $3.1 million that we

Table of Contents

acquired through the reverse merger in May 2004, of which, approximately $0.4 million is available to us to use in equal amounts through 2023. We have applied a valuation allowance against the portion of the federal tax loss carry-forward that has been disallowed through IRC Section 382.

Note 11 Related Party Transactions

Laird Q. Cagan, a member of our Board of Directors, is a Managing Director and co-owner of Cagan McAfee Capital Partners, LLC (CMCP). CMCP has performed financial advisory services to us pursuant to a written agreement amended in December 2008. Also pursuant to the Agreement, Mr. Cagan, as a registered representative of Colorado Financial Services Corporation and as a partner of CMCP, could serve as our placement agent in private equity financings, wherein CMCP could earn cash fees equal to 8% of gross equity proceeds, declining to 4% subject to the amount of equity raised through CMCP, and a fixed 4% warrant fee. We have not paid placement fees to CMCP under this agreement since May 2006.

On October 27, 2009, we issued CMCP 119,795 shares of common stock through a net cashless exercise of a placement warrant. The placement warrant, which was issued to CMCP on May 26, 2004 in connection with a financing transaction, gave CMCP the right to purchase 165,000 shares of common stock, with an exercise price of $1.00 per share.

On March 31, 2011, 58,350 shares of common stock were issued through a net cashless exercise of placement warrants. The placement warrants, which were issued to Laird Cagan, a related party, in 2004 in connection with a financing transaction, gave Mr. Cagan the right to purchase 66,943 shares, with a weighted average exercise price of $1.00 per share.

On May 3, 2012, we issued Laird Cagan 65,261 shares of common stock through a net cashless exercise of a placement warrant. The placement warrant, which was issued to Mr. Cagan on May 6, 2005 in connection with a financing transaction, gave him the right to purchase 91,200 shares of common stock, with an exercise price of $2.50 per share.

See also Note 7 for equity transactions with related parties.

Note 12 Net Income (Loss) Per Share

The following table sets forth the computation of basic and diluted net income (loss) per share:

		Year Ended June 30,	
	2012	**2011**	**2010**
Numerator			

Net income (loss) attributable to common shareholders	$	4,501,739	$	(241,553)	$	(2,387,707)
Denominator						
Weighted average number of common shares Basic		27,784,298		27,437,496		27,004,066
Effect of dilutive securities:						
Common stock warrants issued in connection with equity and financing transactions		63,319				
Stock Options and Incentive Warrants		3,762,312				
Total weighted average dilutive securities		3,825,631				
Weighted average number of common shares and dilutive potential common shares used in diluted EPS		31,609,929		27,437,496		27,004,066
Net income (loss) per common share Basic	$	0.16	$	(0.01)	$	(0.09)
Net income (loss) per common share Diluted	$	0.14	$	(0.01)	$	(0.09)

* Potential dilutive common shares are excluded from the computation of net loss per common shares because their effect will always be anti-dilutive.

Table of Contents

Outstanding potentially dilutive securities as of June 30, 2012 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price		Outstanding at June 30, 2012
Common stock warrants issued in connection with equity and financing transactions	$	2.50	1,165
Stock Options and Incentive Warrants	$	1.83	5,485,820
Total	$	1.83	5,486,985

Outstanding potentially dilutive securities as of June 30, 2011 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price		Outstanding at June 30, 2011
Common stock warrants issued in connection with equity and financing transactions	$	2.50	92,365
Stock Options and Incentive Warrants	$	1.85	5,392,820
Total	$	1.86	5,485,185

Outstanding potentially dilutive securities as of June 30, 2010 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price		Outstanding at June 30, 2010
Common stock warrants issued in connection with equity and financing transactions	$	1.87	159,308
Stock Options and Incentive Warrants	$	1.83	5,482,820
Total	$	1.83	5,642,128

Note 13 - Unsecured Revolving Credit Agreement

On February 29, 2012, Evolution Petroleum Corporation entered into a Credit Agreement (the Credit Agreement) with Texas Capital Bank, N.A. (the Lender). The Credit Agreement provides the Company with a revolving credit facility (the facility) in an amount up to $50,000,000 with availability governed by an Initial Borrowing Base of $5,000,000. A portion of the facility not in excess of $1,000,000 is available for the issuance of letters of credit.

The facility is unsecured and has a four year term. The Company s subsidiaries guaranteed the Company s obligations under the facility. The proceeds of any loans under the facility are to be used by the Company for the acquisition and development of Oil and Gas Properties (as defined in the facility), the issuance of letters of credit, and for working capital and general corporate purposes.

Semi-annually, the Borrowing Base and a Monthly Reduction Amount are re-determined from reserve reports. Requests by the Company to increase the $5,000,000 initial amount are subject to the Lender s credit approval process, and are also limited to 25% of the value Oil and Gas Properties.

At the Company s option, borrowings under the facility bear interest at a rate of either (i) an adjusted LIBOR rate (LIBOR rate divided by the remainder of 1 less the Lender s Regulation D reserve requirement), or (ii) an adjusted Base Rate equal to the greater of the Lender s prime rate or the sum of 0.50% and the Federal Funds Rate. A maximum of three LIBOR based loans can be outstanding at any time. Allowed loan interest periods are one, two, three and six months. LIBOR interest is payable at the end of the interest period except for six-month loans for which accrued interest is payable at three months and at end of term. Base Rate interest is payable monthly. Letters of credit bear fees reflecting 3.5% per annum rate applied to their principal amounts and are due when transacted. Their maximum term is one year.

A commitment fee of 0.50% per annum accrues on unutilized availability and is payable quarterly. The Company is responsible for certain administrative expenses of the Lender over the life of the Credit Agreement as well as for compensating the Lender $50,000 for incurred loan costs upon closing.

Table of Contents

The Credit Agreement also contains financial covenants including a requirement that the Company maintain a current ratio of not less than 1.5 to 1; a ratio of total funded Indebtedness to EBITDA of not more than 2.5 to 1, and a ratio of EBITDA to interest expense of not less than 3 to 1. The agreement specifies certain customary covenants, including restrictions on the Company and its subsidiaries from pledging their assets, incurring defined Indebtedness outside of the facility other that permitted indebtedness, and it restricts certain asset sales. Payments of dividends for the Series A Preferred are only restricted by the EBITDA to interest coverage ratio, wherein Series A dividends are a 1X deduction from EBITDA (as opposed to a 3:1 requirement if dividends were treated as interest expense). The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the Lender may declare all amounts outstanding under the Credit Agreement to be immediately due and payable.

As of June 30, 2012, the Company had no borrowings and no outstanding letters of credit issued under the facility, resulting in an available borrowing base capacity of $5,000,000. The Company was in compliance with all the covenants of the Credit Agreement.

In connection with this agreement the Company incurred $163,257 of debt issuance costs, which have been capitalized in Other Assets and are being amortized on a straight-line basis over the term of the agreement.

Note 14 Commitments and Contingencies

We are subject to various claims and contingencies in the normal course of business. In addition, from time to time, we receive communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdiction in which we operate. We disclose such matters if we believe it is reasonably possible that a future event or events will confirm a loss through impairment of an asset or the incurrence of a liability. We establish reserves if we believe it is probable that a future event or events will confirm a loss and we can reasonably estimate such loss. Furthermore, we will disclose any matter that is unasserted if we consider it probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable. We expense legal defense costs as they are incurred.

On March 29, 2012, the Fifth District Court of Richland Parish Louisiana dismissed the case against the Company and our wholly owned subsidiary NGS Sub Corp. brought by John C. McCarthy et. al. (the plaintiffs) in July 2011. Plaintiffs alleged, among other claims, that we fraudulently and wrongfully purchased plaintiffs income royalty rights in the Delhi Field Unit in the Holt-Bryant Reservoir in May 2006. The Court found that plaintiffs had no cause of action under Louisiana law. The plaintiffs have filed an appeal.

On July 26, 2012, we agreed to settle a lawsuit filed by Frederick M. Garcia and Lydia Garcia in December 2010 in which the plaintiffs alleged failure to maintain the lease beyond its primary term due to no production. Although we believed that the claims were without merit, we chose to settle for $67,000 in return for an extension of the lease, an amount less than our expected cost to prevail in court.

On August 23, 2012, we, and our wholly owned subsidiary NGS Sub Corp and Robert S. Herlin, our President, were served with a lawsuit filed in federal court by James H. and Kristy S. Jones (the Jones lawsuit). The plaintiffs allege primarily that the defendants wrongfully purchased the plaintiffs 0.048119 overriding royalty interest in the Delhi Unit in January 2006 by failing to divulge the existence of an alleged previous agreement to develop the Delhi Field for EOR. We believe that the claims are without merit and are not timely, and we intend to vigorously defend against the claims. Counsel has advised us that, based on information developed to date, the risk of loss in this matter is remote.

Lease Commitments. We have a non-cancelable operating lease for office space that expires on August 1, 2016. Future minimum lease commitments as of June 30, 2012 under this operating lease are as follows:

For the year ended June 30,		
2013		159,011
2014		159,011
2015		159,011
2016		159,011
Thereafter		13,251
Total	$	649,295

Rent expense for the year ended June 30, 2012, 2011 and 2010 was $147,233, $146,263 and $138,823, respectively.

Employment Contracts. We have entered into employment agreements with the Company s three senior executives. The employment contracts provide for a severance package for termination by the Company for any reason other than cause or permanent disability, or in the event of a constructive termination, that includes payment of base pay and certain medical and disability benefits

Table of Contents

from six months to a year after termination. The total contingent obligation under the employment contracts as of June 30, 2012 is approximately $588,000.

Note 15 Concentrations of Credit Risk

Major Customers. We market all of our oil and natural gas production from the properties we operate. The majority of our operated gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-based prices. The following table identifies customers from whom we derived 10 percent or more our net oil and natural gas revenues during the years ended June 30, 2012, 2011 and 2010. Based on the current demand for oil and natural gas and availability of other customers, we do not believe the loss of any of these customers would have a significant effect on our operations or financial condition.

	Percent of Total Revenue		
Customer	**Year Ended June 30, 2012**	**Year Ended June 30, 2011**	**Year Ended June 30, 2010**
Plains Marketing L.P. (includes Delhi production)	84%	60%	12%
Enterprise Crude Oil LLC	7%	15%	31%
ETC Texas Pipeline, LTD.	3%	12%	19%
DCP Midstream, LP	2%	6%	15%
Copano Field Services/Upper Gulf Coast, L.P.	3%	7%	23%
Flint Hills Resources, LP	1%	%	%

Accounts Receivable. Substantially all of our accounts receivable result from uncollateralized oil and natural gas sales to third parties in the oil and natural gas industry. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Cash and Cash Equivalents and Certificates of Deposit. We are subject to concentrations of credit risk with respect to our cash and cash equivalents, which we attempt to minimize by maintaining our cash and cash equivalents in high quality money market funds. At times cash balances may exceed limits federally insured by the Federal Deposit Insurance Corporation (FDIC). Our certificates of deposit are below or at the maximum federally insured limit set by the FDIC.

Note 16 Retirement Plan

Effective February 1, 2007, we implemented a 401(k) Savings Plan which covers all full-time employees. At our discretion, we may match a certain percentage of the employees contributions to the plan. The matching percentage is currently 100% of the first 6% of each participant s compensation, vesting fully upon our contributions. Our matching contribution to the plan was $84,738, $77,168 and $87,846 for the years ended June 30, 2012, 2011 and 2010, respectively.

Note 17 Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited)

Costs incurred for oil and natural gas property acquisition, exploration and development activities

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Development costs also include amounts incurred due to the recognition of asset retirement obligations, of $93,522, $15,000 and $85,871, during the years ended June 30, 2012, 2011 and 2010, respectively.

Table of Contents

	For the Years Ended June 30		
	2012	2011	2010
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$ 115,637	$ 465,176	$ 391,785
Unproved property	5,544,217	523,591	185,154
Exploration costs	3,016,924	215,660	2,354,239
Development costs	238,463	2,200,905	890,116
Total costs incurred for oil and natural gas activities	$ 8,915,241	$ 3,405,332	$ 3,821,294

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of the net proved oil and natural gas reserves of our oil and gas properties located entirely within the United States of America are based on evaluations prepared by third-party reservoir engineers. Reserve volumes and values were determined under the method prescribed by the SEC for our fiscal years ended June 30, 2012, 2011 and 2010, which requires the application of the previous 12-month unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected reserve life, when estimating whether reserve quantities are economical to produce

Proved oil and natural gas reserves are estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and natural gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Table of Contents

Estimated quantities of proved oil and natural gas reserves and changes in quantities of proved developed and undeveloped reserves for each of the periods indicated were as follows

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
Proved developed and undeveloped reserves:				
June 30, 2009	945,948	1,054,294	6,358,788	3,060,040
Revisions of previous estimates	(113,487)	(19,147)	430,145	(60,943)
Improved recovery, extensions and discoveries	9,451,758	29,300	381,695	9,544,674
Production (sales volumes)	(29,749)	(27,820)	(407,674)	(125,515)
June 30, 2010	10,254,470	1,036,627	6,762,954	12,418,256
Revisions of previous estimates	1,475,918	(84,154)	3,273,846	1,937,405
Improved recovery, extensions and discoveries			779,556	129,926
Sales of minerals in place	(104,577)	(221,469)	(1,173,850)	(521,688)
Production (sales volumes)	(57,965)	(18,704)	(238,607)	(116,437)
June 30, 2011	11,567,846	712,300	9,403,899	13,847,462
Revisions of previous estimates	84,219	(212,677)	(1,295,893)	(344,440)
Improved recovery, extensions and discoveries	137,634	5,461	18,925	146,249
Sales of minerals in place				
Production (sales volumes)	(151,081)	(12,611)	(266,775)	(208,155)
June 30, 2012	11,638,618	492,473	7,860,156	13,441,116
Proved developed reserves:				
June 30, 2009	104,731	141,372	1,106,028	430,441
June 30, 2010	706,053	157,302	1,536,858	1,119,498
June 30, 2011	4,986,337	100,900	1,543,401	5,344,471
June 30, 2012	7,670,934	111,978	1,499,382	8,032,809

During our fiscal year ended June 30, 2012, total proved reserves decreased 0.4 million BOE from 13,847,462 BOE at June 30, 2011 to 13,441,116 BOE at June 30, 2012. The decrease is primarily attributable to our production, downward revisions of 127 MBOE for our Woodford properties in Oklahoma and 369 MBOE for lease terminations in Giddings Fields, partially offset by a 210 MBOE upward revision at Delhi and 146 MBOE for extensions in South Texas and acquired well bores in the Giddings Fields. The upward revision in proved oil reserves in the Delhi Field is due primarily to a slight acceleration in the projected reversion date of our approximately 24% working interest based on performance to date.

During our fiscal year ended June 30, 2011, total proved reserves increased 1.4 million BOE from 12,418,256 BOE at June 30, 2010 to 13,847,462 BOE at June 30, 2012. The increase is primarily attributable to upward revisions in both the Delhi Field and our Giddings Field, partially offset by sales in place of reserves in the Giddings Field. The upward revision of 1,475,918 BO in proved oil reserves is due primarily to a more than two year acceleration in the projected reversion date of our 24% working interest, based on operating performance to date. The upward revision of 3,273,846 Mcf is primarily due to re-categorizing probable reserves into the proved category for our properties in the Giddings Field, as a result of drilling results during the year. Sales in place of 521,688 BOE in the Giddings Field are primarily due to the industry drilling joint venture we entered into early in the year.

Total proved reserves increased 9.4 million BOE from 3,060,040 BOE at June 30, 2009 to 12,418,256 BOE at June 30, 2010. The increase is primarily attributable to improved recovery of 9,411,841 barrels of proved oil reserves added to our properties in the Delhi Field, based on approximately $300 million of development capital spent by the Operator since project inception, the start-up of CO2 injection operations during fiscal year 2010, and oil production response during fiscal year 2010. The additions to our properties in the Delhi Field along with extensions in

Giddings and Oklahoma of 127,905 BOE, were offset by production of 125,515 BOE and negative revisions of 60,943 BOE primarily related to the transfer of four well locations in the Lopez Field in South Texas from the proved classification to probable during 2010.

Table of Contents

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales and production and development costs have been estimated using prices and costs in effect at the end of the years indicated, as required by ASC 932, *Disclosures about Oil and Gas Producing Activities* (ASC 932). ASC 932 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing our proved oil and natural gas reserves assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to our proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company s proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of our proved reserves.

The standardized measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2012, 2011 and 2010 are as follows:

	For the Years Ended June 30		
	2012	**2011**	**2010**
Future cash inflows	$ 1,355,686,188	$ 1,161,278,060	$ 827,902,260
Future production costs and severance taxes	(458,716,938)	(379,493,392)	(222,826,052)
Future development costs	(38,458,724)	(40,571,895)	(34,024,112)
Future income tax expenses	(296,703,838)	(278,455,798)	(213,063,769)
Future net cash flows	561,806,688	462,756,975	357,988,327
10% annual discount for estimated timing of cash flows	(278,209,195)	(234,309,020)	(196,361,678)
Standardized measure of discounted future net cash flows	$ 283,597,493	$ 228,447,954	$ 161,626,649

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12-month unweighted arithmetic average first-day-of-the-month commodity prices for each year and reflect adjustments for lease quality, transportation fees, energy content and regional price differentials.

	Year Ended June 30,					
	2012		**2011**		**2010**	
	Oil (Bbl)	**Gas (MMBtu)**	**Oil (Bbl)**	**Gas (MMBtu)**	**Oil (Bbl)**	**Gas (MMBtu)**
NYMEX prices used in determining future cash flows	$ 95.67	$ 3.15	$ 90.09	$ 4.21	$ 75.76	$ 4.10

The NGL price that was utilized was based on the historical price received versus the NYMEX basis oil price.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved crude oil, natural gas liquids, and natural gas reserves is as follows:

	For the Years Ended June 30		
	2012	2011	2010
Balance, beginning of year	$ 228,447,954	$ 161,626,649	$ 23,549,791
Net changes in sales prices and production costs related to future production	76,942,613	57,178,860	3,935,863
Changes in estimated future development costs	6,340,123	(16,028,728)	(3,502,403)
Sales of oil and gas produced during the period, net of production costs	(16,187,039)	(6,151,549)	(3,356,822)
Net change due to purchases of minerals in place			
Net change due to extensions, discoveries, and improved recovery	1,606,122	623,446	236,828,138
Net change due to revisions in quantity estimates	(11,975,496)	56,766,220	(934,602)
Net change due to sales of minerals in place		(8,233,734)	
Development costs incurred during the period	(2,639,398)	2,416,565	
Accretion of discount	22,568,868	26,597,834	3,582,622
Net change in discounted income taxes	(15,026,628)	(42,490,270)	(91,991,767)
Other	(6,479,626)	(3,857,339)	(6,484,171)
Balance, end of year	$ 283,597,493	$ 228,447,954	$ 161,626,649

Table of Contents

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

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

As required by Securities and Exchange Commission Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of the Company s management, including our Chief Executive Officer and the Company s Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that the information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

Management s Report on Internal Control Over Financial Reporting

The Company s management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act), as a process designed by, or under the supervision of, the company s principal executive and principal financial officers and effected by the Company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company s internal control over financial reporting based on criteria established

Table of Contents

in the Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2012.

Changes in Internal Control Over Financial Reporting

There has been no change in the Company s internal control over financial reporting during the fourth quarter ended June 30, 2012 that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Item 9B. Other Information

None.

Table of Contents

PART III

Item 10. Directors, Executive Officers And Corporate Governance

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2012 fiscal year.

Item 11. Executive Compensation

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2012 fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2012 fiscal year.

Item 13. Certain Relationships and Related Transactions, Director Independence

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2012 fiscal year.

Item 14. Principal Accountant Fees and Services

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2012 fiscal year.

PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. Financial Statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Cash Flows

Consolidated Statements of Stockholders Equity

Notes to the Consolidated Financial Statements

2. Financial Statements Schedules and supplementary information required to be submitted:

None.

3. Exhibits

A list of the exhibits filed or furnished with this report on Form 10-K (or incorporated by reference to exhibits previously filed or furnished by us) is provided in the Exhibit Index of this report. Those exhibits incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Otherwise, the exhibits are filed herewith.

Table of Contents

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized in the City of Houston, Texas, on the date indicated.

Evolution Petroleum Corporation

By:	*/s/*	*ROBERT S. HERLIN* *Robert S. Herlin* *Chairman, President and Chief Executive Officer* *(Principal Executive Officer)*

Date: September 13, 2012

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date		Signature	Title
September 13, 2012	*/s/*	*ROBERT S. HERLIN* *Robert S. Herlin*	*Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)*
September 13, 2012	*/s/*	*STERLING H. MCDONALD* *Sterling H. McDonald*	*Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)*
September 13, 2012	*/s/*	*EDWARD J. DIPAOLO* *Edward J. DiPaolo*	*Director*
September 13, 2012	*/s/*	*GENE STOEVER* *Gene Stoever*	*Director*
September 13, 2012	*/s/*	*WILLIAM DOZIER* *William Dozier*	*Director*
September 13, 2012	*/s/*	*KELLY W. LOYD* *Kelly W. Loyd*	*Director*
September 13, 2012	*/s/*	*LAIRD Q. CAGAN* *Laird Q. Cagan*	*Director*

Table of Contents

INDEX OF EXHIBITS

MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
2.1	Asset Purchase Agreement for Tullos Field, dated September 3, 2004 (Previously filed as an exhibit to Form 8-K on September 9, 2004)
2.2	Definitive Asset Purchase Agreement, dated as of February 2, 2005, by and between Chadco, Inc., Alan Chadwick McCartney, Sonya McCartney and NGS Sub. Corp. (Previously filed as an exhibit in Form 8-K on February 8, 2005)
2.3	Purchase and Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on May 11, 2006)
2.4	Purchase and Sale Agreement I, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.5	Purchase and Sale Agreement II, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.6	Conveyance, Assignment and Bill of Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.7	Agreement and Plan of Reorganization dated as of April 12, 2004 among Reality Interactive, Inc., Reality Acquisition Corp., Global Marketing Associates, Inc., Dean H. Becker and Natural Gas Systems, Inc. (incorporated by reference to the Current Report on Form 8-K/A filed by Natural Gas Systems, Inc. with the Securities and Exchange Commission on April 27, 2004) (Previously filed as an exhibit to Form Schedule 13D on July 11, 2008)
3.1	Articles of Incorporation (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 7, 2002)
3.2	Certificate of Amendment to Articles of Incorporation (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 7, 2002)
3.3	Certificate of Amendment to Articles of Incorporation (Previously filed as an exhibit to Form SB 2/A on October 19, 2005)
3.4	Bylaws (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 7, 2002)
3.5	Amended Bylaws (Previously filed as an exhibit to Form 10KSB on March 31, 2004)
4.1	Form of Stock Option Agreement for the Natural Gas Systems 2004 Stock Plan (Previously filed as an exhibit to the Current Report on Form 8 K on April 8, 2005)
4.2	Articles of Merger (Previously filed as an exhibit to Form SB 2/A on October 19, 2005)
4.3	Form of Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP (Previously filed as an exhibit to the Company s Current Report on Form 8-K on April 8, 2005)
4.4	Revocable Warrant Agreement between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company s Current Report on Form 8-K on June 29, 2005)

4.5	Specimen form of the Company s Common Stock Certificate (Previously filed herewith as an exhibit to Form SB 2/A on October 19, 2005)
4.6	Securities Purchase Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company s Current Report on Form 8-K on May 11, 2005)

Table of Contents

4.7	Registration Rights Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company s Current Report on Form 8-K on May 11, 2005)
4.8	Stock Grant Agreement, dated as of May 4, 2005, by and between Natural Gas Systems, Inc. and Liviakis Financial Communications, Inc. (Previously filed as an exhibit to the Company s Current Report on Form 8-K on May 11, 2005)
4.9	Herlin Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on April 8, 2005)
4.10	Revocable Warrant Agreement between Natural Gas Systems, Inc. and Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on April 8, 2005)
4.11	Amended and Restated Tatum Resources Agreement, dated January 1, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on April 8, 2005)
4.12	Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP, dated January 1, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on April 8, 2005)
4.13	McDonald Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on April 8, 2005)
4.14	Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 8, 2005)
4.15	Natural Gas Systems, Inc. Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 8, 2005)
4.16	Revocable Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 8, 2005)
4.17	Natural Gas Systems, Inc. Revocable Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 8, 2005)
4.18	Registration Rights Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Holders of Common Stock of Natural Gas Systems, Inc. (Previously filed as an exhibit to the Company s Current Report on Form 8-K on February 8, 2005)
4.19	Form of Registration Rights Agreement (Previously filed as an exhibit to the Company s Current Report on Form 8-K on October 26, 2004)
4.20	2004 Stock Plan (Previously filed as an exhibit to the Company s Definitive Information Statement on Schedule 14C on August 9, 2004)
4.21	2003 Stock Option Plan, adopted September 25, 2003 (Previously filed as an exhibit to the Company s Form 8-K on January 24, 2007)
4.22	Amended and Restated 2004 Stock Plan, adopted December 4, 2007 (previously filed as an exhibit to the Company s Definitive Information Statement on Schedule 14A on October 29, 2007)
4.23	Stock Option Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company s Report on Form 8-K on June 29, 2005)
4.24	Stock Option Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company s Current Report on Form 8-K on June 29, 2005)

79

4.25	Stock Option Grant Agreement dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company s Current Report on Form 8-K on June 29, 2005)
4.26	Securities Purchase Agreement dated as of January 13, 2006, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company s Current Report on Form 8-K on January 20, 2006)
4.27	Third Revocable Warrant Agreement, by and between Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB 2/A on March 3, 2006)
4.28	Third Revocable Warrant Agreement, by and between Prospect Energy Corporation and Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB 2/A on March 3, 2006)
4.29	Subordinated Promissory Note, dated March 3, 2006, between Natural Gas Systems, Inc. and Laird Q. Cagan (Previously filed as an exhibit to Form 8-K on March 8, 2006)
4.30	Form of Restricted Stock Agreement (Previously filed as an exhibit to Form 8-K on May 15, 2009)
4.31	Form of Senior Indenture (Previously filed as an exhibit to Form S-3 on May 15, 2009)
4.32	Form of Senior Indenture (Previously filed as an exhibit to Form S-3 on July 14, 2010)
4.33	Form of Subordinated Indenture (Previously filed as an exhibit to Form S-3 on July 14, 2010)
4.34	Amendment to Amended and Restated 2004 Stock Plan, adopted December 5, 2011 (previously filed as an exhibit to the Company s Definitive Information Statement on Schedule 14A on October 28, 2011).
10.1	Third Amendment to Consulting Agreement between Liviakis Financial Communications, Inc. and Evolution Petroleum dated November 14, 2006 (Previously filed as an exhibit to Form 10-QSB on February 14, 2007)
10.2	Executive Employment Agreement of Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.3	Executive Employment Agreement of Sterling H. McDonald, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.4	Executive Employment Agreement of Daryl V. Mazzanti, dated June 23, 2005 (Previously filed as an exhibit to Form 8-K on June 29, 2005)
10.5	Master Services Agreement, dated September 29, 2005, by and between the NGS Technologies, Inc. and MTEM, Ltd. (Previously filed as an exhibit on Form 8-K on October 7, 2005)
10.6	Agreement with Chadbourn Securities, Inc., dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
10.7	Agreement with Cagan McAfee Capital Partners, LLC, dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
10.8	Unit Operating Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
10.9	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (Previously filed as an exhibit to Form 8-K on September 22, 2006)
10.10	Asset Purchase and Sale Agreement by and between NGS SUB. CORP. (Seller) and MWM Energy, LLC (Buyer), dated February 15, 2008 (Previously filed as an exhibit to Form 10-Q on May 14, 2008)

10.11	Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (Previously filed as Annex A to Form Schedule 14A on October 29, 2007)
10.12	Gas Purchase and Gas Processing Contract by and between EVOLUTION OPERATION CO., INC. (Seller) and ETC TEXAS PIPELINE LTD. (Buyer) dated October 8, 2007 (Previously filed as an exhibit to Form 10-K/A on April 7, 2009)

Table of Contents

10.13	Gas Purchase Contract by and between EVOLUTION OPERATION CO., INC. (Seller) and DCP MIDSTREAM, LP (Buyer) dated December 1, 2007 (Previously filed as an exhibit to Form 10-K/A on April 7, 2009)
10.14	Gas Purchase and Sale Agreement by and between EVOLUTION OPERATION CO., INC. (Seller) and COPANO FIELD SERVICES/UPPER GULF COAST, L.P. (Buyer) dated February 1, 2009 (Previously filed as an exhibit to Form 10-Q on May 15, 2009)
10.15	Credit Agreement dated February 29, 2012 among Evolution Petroleum Corporation, the Guarantors and Texas Capital Bank N.A. (incorporated by reference as Exhibit 10.1 to the Company s Form 8-K filed with the SEC on March 6, 2012.
10.16	Lease Acquisition Agreement Cowboy Prospect by and between Evolution Petroleum OK, Inc. and Orion Exploration Partners, LLC dated April 17, 2012 (incorporated by reference as Exhibit 10.1 to the Company Form 8-K/A filed with the SEC on August 21, 2012)
10.17	Participation and AMI Agreement by and between Orion Exploration Partners, LLC and Evolution Petroleum OK, Inc. dated April 17, 2012 (incorporated by reference as Exhibit 10.2 to the Company Form 8-K/A filed with the SEC on August 21, 2012)
14.1	Code of Business Conduct and Ethics for Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
21.1	List of Subsidiaries of Evolution Petroleum Corporation (Filed herein)
23.1	Consent of Hein & Associates, LLP, independent auditors (Filed herein)
23.2	Consent of W. D. Von Gonten & Co. (Filed herein)
23.3	Consent of DeGolyer and MacNaughton (filed herein)
23.4	Consent of Pinnacle Energy Services, LLC (filed herein)
31.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
31.2	Certification of Chief Financial Officer Sterling H. McDonald Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.2	Certification of Chief Financial Officer Sterling H. McDonald Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
99.1	Audit Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.2	Compensation Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.3	Nominating Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.4	The summary of W.D. Von Gonten & Co. Report as of June 30, 2012, on oil and gas reserves (SEC Case) dated August 6, 2012 and certificate of qualification (Filed herein)
99.5	

	The summary of DeGolyer and MacNaughton s Report as of June 30, 2012, on oil and gas reserves (SEC Case) dated August 8, 2012 and certificate of qualification (Filed herein)
99.6	The summary of Pinnacle Energy Services, LLC Report as of June 30, 2012, on oil and gas reserves (SEC Case) dated July 31, 2012 and certificate of qualification (Filed herein)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document