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 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.

22

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.

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

			Gross (Net)			
Area	**Gross Developed Acres**	**Net Developed Acres**	**Producing Wells**		**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

	Number of securities to be issued upon	Weighted-average exercise	Number of securities remaining available for future