EVOLUTION PETROLEUM CORP
Form 10-K
September 13, 2011
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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, 2011

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 Amex
8.5% Series A Cumulative Preferred Stock, $0.001 par value	NYSE Amex

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: o 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 o
Non-accelerated filer o	Smaller reporting company x

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 aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2010, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $6.52 on the NYSE Amex was $110,018,265.

The number of shares outstanding of the registrant s common stock, par value $0.001, as of September 12, 2011, was 27,441,674.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant s 2011 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.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

2011 ANNUAL REPORT ON FORM 10-K

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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.

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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.

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.

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 gasolines 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. *

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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.

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.

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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.

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).

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.

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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 Amex 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, 2011, we had eleven 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) 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 control of our assets for the benefit of our shareholders, including approximately 20% beneficially owned by all of our employees.

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

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

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

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 asset. 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 68 million barrels of additional recovery from the flooding operation, approximately 25% higher than our initial gross estimate at the time of the farmout.

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, as defined, 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 26.5%. Our current independent reserve report dated June 30, 2011 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, 2011:

- 10,937 MBBLS of proved oil reserves, with a PV-10 of $333.6 million *

- 5,838 MBBLS of probable oil reserves, with a PV-10 of $72.4 million *

- 45% of proved volumes are developed producing.

- 33% of probable reserves are developed producing.

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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 can not be reconciled to a GAAP measure.

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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, and accounted for approximately 2% of Q3-11 sales volumes.

Phase III is currently being installed with first CO_2 injection expected during calendar 2011. We expect that the remaining phases will be installed similarly over the next few years and are scheduled to be similar in size as Phase II, as compared to the much smaller Phase I.

During Q4-11, Delhi s Louisiana Light Sweet (LLS) crude oil sales realized a 14% price premium over the sales price we received from our Giddings production in central Texas. We expect that a similar market differential may continue into fiscal 2012.

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 leveraged 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 adapted to further develop and produce the Austin Chalk, Georgetown and Buda formations in the Giddings Field in central Texas;

- We sought projects that could provide substantial early revenues, production and net cash flows prior to future expected production from the Delhi Field;

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

- We sought exposure to both crude oil and natural gas opportunities.

Giddings Field Central Texas

We began leasing activities in the Giddings Field in December 2006 and currently hold 4,788 net developed acres and hold approximately 4,350 net acres as undeveloped and associated with our proved drilling locations as of June 30, 2011. 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, 2011, 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 2011 as part of a joint venture to which we contributed our 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 producing well in another reservoir.

Total net proved reserves assigned to our properties in the Giddings Field by our independent reservoir engineer, W.D. Von Gonten & Associates, are 2,721 MBOE as of June 30, 2011. The total is a decrease of 263 MBOE from June 30, 2010 due to Giddings production during the year of 71 MBOE, sales of 522 MBOE in place and upwards revisions totaling 331 MBOE. Our total investment of $28.3 million to date has generated cash flows from 357.4 MBOE of total net production and proved PV-10 at June 30, 2011 of $40.8 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 (Neptune Oil Project) - South Texas

We currently own leases on approximately 764 net acres in the Lopez Field in South Texas as part of our Neptune Oil Project. As of June 30, 2011, our independent reservoir engineer, W.D. Von Gonten & Associates, recognized one proved producing location and five proved well locations with 61 MBO of proved reserves. The engineer further assigned 378 MBO of probable reserves to 36 gross and net locations. Production testing of the Lopez Field was briefly suspended early in fiscal 2011 due to a delay in obtaining the necessary salt water disposal permit, which was received during the second quarter and following which receipt production was resumed.

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Artificial Lift Technology (GARP) Worldwide

Our artificial lift technology, GARP (Gas Assisted Rod Pump), was developed by one of our officers, Daryl Mazzanti. Its design is intended to extend the life of horizontal wells with oil or associated water production with the expectation of recovering an additional 10-15% of cumulative recovery at a cost < $10 BOE. The Company has applied for a patent in regard to GARP technology and a Notice of Allowance was issued by the USPTO on June 13, 2011. We have remitted the required issue fee and publication fee. Letters patent for the GARP technology should be issued in due course.

The GARP technology has undergone testing on a few late stage producers we own in our Giddings portfolio. 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.

To prove commercial application, we are working to gain access to average or above average cumulative producers owned by third parties. We are currently continuing industry joint venture negotiations with two third parties to demonstrate the technology in exchange for an interest in the newly re-established production. One candidate has agreed to the demonstration well, but documentation of the joint venture is not yet complete. The Company is in the beginning stages of negotiations with a second candidate.

If successful, GARP could be applicable to a large set of late stage producing wells, worldwide.

Unconventional Gas Resources

Woodford Shale Projects in Oklahoma Southeast Oklahoma

Also following the closing of our Delhi Farmout in June 2006, we began the process of identifying unconventional natural gas resource projects, to balance the oily nature of our anticipated Delhi reserves. Following are the parameters we sought.

- Low drilling risks with low to moderate well costs
- Low reserve risk
- Repeatable development performance across a substantial acreage position

- Acceptable profitability at $5 NYMEX natural gas prices

These parameters led us to the shallower eastern extension of the Woodford Shale in Eastern Oklahoma.

Haskell County

We currently own 5,354 net acres in Haskell County we believe is prospective in the Woodford Shale and a second zone. The Woodford Shale generally lies between 4,000   and 6,000   in depth across our leasehold that is located in more than 30 sections and has been commercially developed to the east, west and south of our leasehold. Our test program began during fiscal 2011 with the re-entry and recompletion of an existing well. During re-entry operations to create a water disposal zone below the targeted Woodford zone, we determined that the disposal zone was gas productive (the   second zone). We subsequently completed in the second zone using a single stage hydraulic fracturing in the vertical well bore. Production is continuing to test the economic viability of further acreage development within this second zone. Our independent reservoir engineer has assigned proved gas reserves of 768 MMCF associated with one gross and net producing well and 5 gross and 1.33 net proved undeveloped locations.

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Wagoner County

The Woodford Shale generally lies at a depth of 1,200 to 1,600 across our leasehold that totals 4,798 net acres. To date, we have production tested the formation in three wells with one good test on the west lease block, one poor test on the southern lease block and one incomplete test on the eastern lease block. Due to the current natural gas market and required infrastructure, we have elected to divest this asset during 2012. We have, therefore, not included any previously established reserves.

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. 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 that accounted for more than 10% of total revenues for 2011, 2010, and 2009.

	Year Ended June 30,		
Customer	**2011**	**2010**	**2009**
Plains Marketing L.P. (includes Delhi production)	60%	12%	40%
Enterprise Crude Oil LLC	15%	31%	5%
ETC Texas Pipeline, LTD.	12%	19%	36%
DCP Midstream, LP	6%	15%	16%
Copano Field Services/Upper Gulf Coast, L.P.	7%	23%	2%

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.

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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 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 during the second half of 2011 due to market imbalances, and this imbalance continues as of June 30, 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.

Similarly, domestic natural gas liquids prices have been volatile, influenced by crude oil price, NGL supply and demand, consolidation among NGL fractionators and natural gas price.

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. We believe that we are in substantial compliance with all laws and regulations applicable to our operations and 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 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 do not have coverage for consequential damages.

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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.

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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. Prior to the Delhi Farmout, we had incurred significant losses since the inception of our oil and natural gas operations and we have since resumed incurring losses until the quarters ended March 31, 2011 and June 30, 2011, which were profitable. 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, 2011, 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.

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 patent pending 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.

Our proprietary 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.

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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 affect 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 affect 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.

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 affect on our operations.

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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 can not 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. 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

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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.

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 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.

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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 affect 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 84% of our proved reserves at June 30, 2011 are crude oil reserves and 5% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices.

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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 affect 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 2012 Budget Proposal includes provisions that would, if enacted, repeal the percentage depletion allowance for oil and natural gas properties, eliminate the immediate deduction for intangible drilling and development costs and eliminate the deduction from income for domestic production activities relating to oil and natural-gas exploration and development, 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, particularly our Oklahoma shale projects.

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 result in our continued or increased operating losses. These factors could negatively impact our operations and may limit our growth.

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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, 2011, our stock price as traded on the NYSE Amex ranged from $4.40 to $8.80. 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; 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 6.2 million shares, or approximately 19% of our beneficial common stock base. JVL Advisors LLC controls approximately 4.5 million shares or approximately 16% 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 Amex. In the year prior to June 30, 2011, the actual daily trading volume in our common stock ranged from 13,514 shares of common stock to a high of 735,396 shares of common stock traded, with 161 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 three 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.

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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 251,150 shares of Series A Preferred Stock are issued and outstanding as of September 12, 2011. 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 Amex under the symbol EPM.PR.A on July 5, 2011 and are thinly traded on the NYSE Amex. 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.

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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, 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. 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 $11,507 with the base rent escalating to a monthly base rate of $13,251 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.

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.

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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.

Proved Reserves Fiscal Year Ended 2011

Our proved reserves at June 30, 2011, denominated in equivalent barrels using a six Mcf of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, totaled 13,848 MBOE. Approximately 39% of our proved reserves were classified as proved developed and 61% were classified as proved undeveloped. Classified by product, 84% of our proved reserves were crude oil, 5% were natural gas liquids, and 11% were natural gas. Our proved reserves as of June 30, 2011 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 16 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

	Proved Developed Producing	**Proved Developed Non-producing**	**Proved Undeveloped**	**Total Proved Reserves**
Crude Oil (MBbls)				
Delhi Field	4,899		6,039	10,937
Lopez Field	12		50	61
Giddings Field	62	14	493	569
Total Crude Oil (MBbls)	4,972	14	6,582	11,568
NGLs (MBbls)				
Giddings Field	82	19	611	712

Total NGLs (MBbls)	82	19	611	712
Natural gas (MMcf)				
Giddings Field	1,347	48	7,241	8,636
Oklahoma	148		619	768
Total Natural gas (MMcf)	1,495	48	7,861	9,404
Total (MBOE)	5,303	42	8,503	13,848
Estimated future net revenues	$ 337,532,310	$ 1,899,193	$ 401,781,270	$ 741,212,773
Estimated future net revenues discounted at 10% (PV-10)	$ 199,512,806	$ 1,019,970	$ 174,805,682	$ 375,338,458

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Proved Reserves Fiscal Year Ended 2010

Our proved 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, totaled 12,418 MBOE. Approximately 9% of our proved reserves were classified as proved developed and 91% were classified as proved undeveloped. Classified by product, 83% of our proved reserves were crude oil, 8% were natural gas liquids, and 9% were natural gas. Our proved reserves as of June 30, 2010 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.

The following table sets forth our estimated proved reserves as of June 30, 2010. See Note 16 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

	Proved Developed Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved Reserves
Crude Oil (MBbls)				
Delhi Field	584	29	8,799	9,412
Giddings Field	81	12	750	843
Total Crude Oil (MBbls)	665	41	9,549	10,255
NGLs (MBbls)				
Giddings Field	143	15	879	1,037
Total NGLs (MBbls)	143	15	879	1,037
Natural gas (MMcf)				
Giddings Field	1,348	51	5,226	6,625
Oklahoma		138		138
Total Natural gas (MMcf)	1,348	189	5,226	6,763
Total (MBOE)	1,032	87	11,299	12,418
Estimated future net revenues	$ 45,604,219	$ 3,483,121	$ 521,964,756	$ 571,052,096
Estimated future net revenues discounted at 10% (PV-10)	$ 29,306,414	$ 2,415,600	$ 234,256,329	$ 265,978,343

Proved Reserves Fiscal Year Ended 2009

Our proved reserves at June 30, 2009, denominated in equivalent barrels using a six Mcf of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, totaled 3,060 MBOE. Approximately 14% of our proved reserves were classified as proved developed and 86% were classified as proved undeveloped. Classified by product, 35% of our proved reserves were natural gas, 34% were natural gas liquids, and 31% were crude oil. Our proved reserves as of June 30, 2009 were estimated by our independent petroleum consultants W.D. Von Gonten & Co. (Von Gonten), and were entirely from our properties in Texas.

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The following table sets forth our estimated proved reserves as of June 30, 2009. See Note 16 to the consolidated financial statements, where additional reserve information is provided. The NYMEX spot prices used to calculate estimated revenues were $69.89 per barrel of crude oil and $3.885 per MMbtu of natural gas as of June 30, 2009. 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, in order to reflect prices actually received at the wellhead. 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, 2009

	Proved Developed Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved Reserves
Crude Oil (MBbls)	105		841	946
NGLs (MBbls)	141		913	1,054
Natural gas (MMcf)	1,106		5,253	6,359
Total (MBOE)	430		2,630	3,060
Estimated future net revenues	$ 9,714,324		$ 48,480,128	$ 58,194,452
Estimated future net revenues discounted at 10% (PV-10)	$ 7,640,456		$ 28,185,766	$ 35,826,222

Changes in Proved Reserves

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.

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During our fiscal year ended June 30, 2010, total proved reserves increased 9,358 MBOE from 3,060 MBOE at June 30, 2009 to 12,418 MBOE at June 30, 2010. The increase is primarily attributable to 9,418 MBbls of proved oil reserves we added to our properties in the Delhi Field, based on approximately $300 million of development capital spent by the Operator since project inception, the start-up of CO2 injection operations during fiscal year 2010, and an oil production response during fiscal year 2010. The additions in our properties in the Delhi Field along with extensions in Giddings and Oklahoma of 126 MBOE, were offset by production of 126 MBOE and negative revisions of 61 MBOE primarily related to the transfer of four well locations in the Lopez Field in South Texas from the proved classification to probable on June 30, 2010.

	Delhi Field	Giddings Field	Lopez Field	Oklahoma	Total
Proved reserves, MBOE					
June 30, 2009		3,012.5	47.5		3,060.0
Production	(6.3)	(119.2)			(125.5)
Revisions		(13.3)	(47.5)		(60.8)
Improved recovery, extensions and discoveries	9,418.1	103.5		22.9	9,544.5
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

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 16 of the consolidated financial statements.

	For the Years Ended June 30 2011	2010
Estimated future net revenues	$ 741,212,773	$ 571,052,096
10% annual discount for estimated timing of future cash flows	(365,874,315)	(305,073,753)
Estimated future net revenues discounted at 10% (PV-10)	375,338,458	265,978,343
Estimated future income tax expenses discounted at 10%	(146,890,504)	(104,351,694)
Standardized Measure	$ 228,447,954	$ 161,626,649

The following table provides a reconciliation of PV-10 of each of our proved properties to the Standardized Measure as shown in Note 16 of the consolidated financial statements.

	For the Years Ended June 30 2011	2010
Delhi Field	$ 333,618,884	$ 224,462,846

Giddings Field		40,800,575		41,337,594
Lopez Field		470,319		
Oklahoma		448,680		177,903
Estimated future net revenues discounted at 10% (PV-10)	$	375,338,458	$	265,978,343
Estimated future income tax expenses discounted at 10%		(146,890,504)		(104,351,694)
Standardized Measure	$	228,447,954	$	161,626,649

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2011 and 2010 Reserves Pricing Sensitivities

In addition to the proved reserves determined using SEC pricing, our independent engineers prepared estimates of our year-end proved reserves using two alternative commodity price assumptions. The following tables summarizes our total proved reserves as of June 30, 2011 and 2010 under each of the three assumptions:

	Total Proved Reserves as of June 30, 2011				
Pricing	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total Reserves (MBOE)**	**PV-10**
SEC	11,568	712	9,404	13,848	$ 375,338,458
Spot price (1)	11,763	713	9,424	14,047	$ 434,053,068
Forward curve (2)	11,813	715	9,585	14,126	$ 471,862,435

(1) The Spot price case is based on the NYMEX spot crude oil, natural gas liquid, and natural gas price as of June 30, 2011. For oil and natural gas liquids, the NYMEX posted price of $95.42 per barrel was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the NYMEX spot price of $4.28 per MMBtu was adjusted by lease for energy content, transportation fees and regional price differentials. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations.

(2) The Forward curve case is based on the five year applicable monthly forward closing prices on the NYMEX for oil and natural gas as of June 30, 2011. For oil and natural gas liquids, the price was based on a crude oil price which increased from $95.42 per Bbl to $101.59 per Bbl during the first five years and then held constant during the remaining life of the reserves, adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the price was based on a natural gas price which increased from $4.28 per MMBtu to $5.88 per MMBtu during the first five years and then held constant over the remaining life of the properties, adjusted by lease for energy content, transportation fees and regional price differentials. Future production and development costs are based on year-end costs with no escalations.

	Total Proved Reserves as of June 30, 2010				
Pricing	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total Reserves (MBOE)**	**PV-10**
SEC	10,255	1,037	6,763	12,418	$ 265,978,343
Spot price (1)	10,106	1,036	6,773	12,270	$ 251,930,278
Forward curve (2)	10,482	1,049	6,894	12,679	$ 308,738,147

(1) The Spot price case is based on the NYMEX spot crude oil, natural gas liquid, and natural gas price as of June 30, 2010. For oil and natural gas liquids, the NYMEX posted price of $75.63 per barrel was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the NYMEX spot price of $4.53 per MMBtu was adjusted by lease for energy content, transportation fees and regional price differentials. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations.

(2) The Forward curve case is based on the five year applicable monthly forward closing prices on the NYMEX for oil and natural gas as of June 30, 2010. For oil and natural gas liquids, the price was based on a crude oil price which increased from $75.63 per Bbl to $84.43 per Bbl during the first five years and then held constant during the remaining life of the reserves, adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the price was based on a natural gas price which increased from $4.53 per MMBtu to $6.07 per MMBtu during the first five years and then held constant over the remaining life of the properties, adjusted by lease for energy content, transportation fees and regional price differentials. Future production and development costs are based on year-end costs with no escalations.

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Probable Reserves Fiscal Year Ended 2011 and 2010

The Modernization Requirements also permitted the disclosure of probable reserves. Probable reserves are additional reserves that are less certain to be recovered than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered. The various reserve categories have different risks associated with them. Proved reserves are more likely to be produced than probable reserves. Because of these risks, the different reserve categories should not be considered to be directly additive.

June 30, 2011

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)		PV-10
Probable developed reserves						
Delhi Field	1,902			1,902	$	33,688,710
Probable undeveloped reserves						
Delhi Field	3,936			3,936	$	38,719,980
Lopez Field	378			378	$	3,198,908
Total probable reserves	6,216			6,216	$	75,607,598

June 30, 2010

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)		PV-10
Probable developed reserves						
Delhi Field	301			301	$	5,955,480
Probable undeveloped reserves						
Delhi Field	5,381			5,381	$	45,229,803
Giddings Field	206	226	3,272	977	$	11,767,618
Lopez Field	283			283	$	785,921
Oklahoma			1,360	227	$	53,907
Total probable reserves	6,171	226	4,632	7,169	$	63,792,729

In addition to the probable reserves determined using SEC pricing, our independent engineers prepared estimates of our year-end probable reserves using two alternative commodity price assumptions. The following tables summarizes our total probable reserves as of June 30, 2011 and 2010 under each of the three assumptions:

	Total Probable Reserves as of June 30, 2011					
Pricing	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total Reserves (MBOE)**		**PV-10**
SEC	6,216			6,216	$	75,607,598

Spot price (1)	6,228	6,228	$	91,639,997
Forward curve (2)	6,236	6,236	$	100,793,015

(1) The Spot price case is based on the NYMEX spot crude oil, natural gas liquid, and natural gas price as of June 30, 2011. For oil and natural gas liquids, the NYMEX posted price of $95.42 per barrel was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the NYMEX spot price of $4.28 per MMBtu was adjusted by lease for energy content, transportation fees and regional price differentials. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations.

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(2) The Forward curve case is based on the five year applicable monthly forward closing prices on the NYMEX for oil and natural gas as of June 30, 2011. For oil and natural gas liquids, the price was based on a crude oil price which increased from $95.42 per Bbl to $101.59 per Bbl during the first five years and then held constant during the remaining life of the reserves, adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the price was based on a natural gas price which increased from $4.28 per MMBtu to $5.88 per MMBtu during the first five years and then held constant over the remaining life of the properties, adjusted by lease for energy content, transportation fees and regional price differentials. Future production and development costs are based on year-end costs with no escalations.

	Total Probable Reserves as of June 30, 2010				
Pricing	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)	PV-10
SEC	6,171	226	4,632	7,169	$ 63,792,729
Spot price (1)	6,117	226	4,670	7,121	$ 60,879,954
Forward curve (2)	6,155	231	4,808	7,188	$ 77,724,411

(1) The Spot price case is based on the NYMEX spot crude oil, natural gas liquid, and natural gas price as of June 30, 2010. For oil and natural gas liquids, the NYMEX posted price of $75.63 per barrel was adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the NYMEX spot price of $4.53 per MMBtu was adjusted by lease for energy content, transportation fees and regional price differentials. Such prices were held constant throughout the estimated lives of the reserves. Future production and development costs are based on year-end costs with no escalations.

(2) The Forward curve case is based on the five year applicable monthly forward closing prices on the NYMEX for oil and natural gas as of June 30, 2010. For oil and natural gas liquids, the price was based on a crude oil price which increased from $75.63 per Bbl to $84.43 per Bbl during the first five years and then held constant during the remaining life of the reserves, adjusted by lease for quality, transportation fees and regional price differentials. For natural gas, the price was based on a natural gas price which increased from $4.53 per MMBtu to $6.07 per MMBtu during the first five years and then held constant over the remaining life of the properties, adjusted by lease for energy content, transportation fees and regional price differentials. Future production and development costs are based on year-end costs with no escalations.

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 and

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, 2011 were 8,503 MBOE. Future development costs associated with our proved undeveloped reserves at June 30, 2011 totaled approximately $39.0 million. The 2,796 MBOE decrease in proved undeveloped reserves from 11,299 MBOE as of June 30, 2010 is primarily attributable to reclassification of 2,760 MBbls of proved oil reserves attributable to our properties in the Delhi Field to the proved developed category, partially offset by a 333 MBOE upward revision of probable undeveloped reserves to proved undeveloped reserves in the Giddings Field and the 50 MBO upward revision in Lopez Field proved undeveloped reserves. None of our proved undeveloped locations remain undeveloped for five years from the date of initial recognition as proved undeveloped reserves.

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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, 2011		Year Ended June 30, 2010		Year Ended June 30, 2009	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Crude oil (Bbls)	57,965	$ 97.86	29,749	$ 73.56	36,026	$ 76.26
Natural gas liquids (Bbls)	18,704	$ 47.77	27,820	$ 38.80	44,125	$ 36.83
Natural gas (Mcf)	238,608	$ 4.04	407,674	$ 4.30	323,301	$ 5.33

Average production costs, including production taxes, per unit of production (using a six to one conversion ratio of Mcf s to barrels) were approximately $12, $13 and $11 per BOE for the years ended June 30, 2011, 2010 and 2009, respectively.

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 the last two weeks of March 2010. Our interests in the Delhi Field consist of more than 79% of our total proved reserves as of June 30, 2011. The average sales price per barrel of crude oil at Delhi was $101.79 for the year ended June 30, 2011, with no associated production costs.

Production from our properties in the Giddings Field decreased 40% from 119,182 BOE during the fiscal year ended June 2010 to 71,280 BOE during the fiscal year ended June 30, 2011. Production of natural gas from our properties in the Giddings Field increased 43%, while production of crude oil and NGLs decreased 37% compared to the year ended June 30, 2010. Our interests in the Giddings Field consist of 20% of our total proved reserves as of June 30, 2011. The average sales price per BOE at Giddings was $42.78 for the year ended June 30, 2011 . The associated production costs in Giddings for the year ended June 30, 2011 (not including ad valorem and production taxes) were $18.29 per BOE.

The decrease in volumes from fiscal 2009 to fiscal 2010 were attributable to the natural production decline of our properties in the Giddings Field, which decreased 11% from 133,863 BOE during the fiscal year ended June 2009 to 119,182 BOE during the fiscal year ended June 30, 2010.

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Drilling Activity

The following table sets forth our drilling activity. In 2011, we drilled and completed 3 gross and 0.6 net wells in the Giddings Field. One gross and net well drilled in Wagoner County, Oklahoma, in 2010 was plugged and abandoned during 2011 as a dry hole.

	Year Ended June 30,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Productive wells drilled						
Development	3.0	0.6	1.0	1.0	2.0	2.0
Exploratory						
Total	3.0	0.6	1.0	1.0	2.0	2.0
Non productive dry wells drilled						
Development						
Exploratory	1.0	1.0				
Total	1.0	1.0				

Present Activities

At year end, we were not actively drilling any wells. Three wells in Oklahoma that were drilled in 2010 and production tested to flare were shut-in as of June 30, 2011 waiting on pipeline connections and, in one case, a workover to repair a mechanical issue, thus all three wells are neither productive or plugged and abandoned. Pressure maintenance through re-injection of produced water is occurring on one of our leases in the Lopez Field. Enhanced oil recovery through CO2 injection is occurring in the Delhi Field.

For further discussion, see Highlights for our fiscal year 2011 and Looking forward into 2011 under *Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations* of this Form 10-K.

Delivery Commitments

As of June 30, 2011, we had no delivery commitments.

Productive Wells and Developed Acreage

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.

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Our developed acreage at June 30, 2009 totaled 5,040 net acres in the Giddings Field, consisting of a 100% working interest in ten gross and net producing wells.

Undeveloped Acreage

As of June 30, 2011, we held approximately 34,131 gross and 17,815 net undeveloped acres in the Gulf Coast and Mid-Continent regions of the United States, as follows:

Field/Area	Gross Acreage	Net Acreage
Giddings Field, Texas	4,574	4,179
Woodford, Oklahoma	15,602	10,052
Neptune Oil Project (Lopez Field, South Texas)	319	319
Delhi Field, Louisiana *	13,636	3,265
Total	34,131	17,815

* 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, (consisting of our acreage in the Giddings Field, Woodford, and South Texas) is approximately 3,431 acres in fiscal 2012, 9,965 acres in fiscal 2013, and 1,154 acres in 2014.

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 12 Commitments and Contingencies under Item 8. Financial Statements for a description of legal proceedings.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of our security holders, through solicitation of proxies or otherwise, during the fourth quarter ended June 30, 2011.

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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 Amex 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 Amex. The following table shows, for each quarter of fiscal year 2011, 2010 and 2009, the high and low sales prices for EPM as reported by the NYSE Amex.

NYSE Amex

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

2009:		**High**		**Low**
Fourth quarter ended June 30, 2009	$	3.13	$	1.85
Third quarter ended March 31, 2009	$	1.99	$	1.17
Second quarter ended December 31, 2008	$	3.06	$	1.00
First quarter ended September 30, 2008	$	6.05	$	2.60

Holders

As of June 30, 2011, there were 27,612,916 shares of common stock issued and outstanding, held by approximately 4,137 holders of record.

Dividends

We have never declared or paid any cash dividends with respect to our common stock. We anticipate that we will retain future earnings for use in the operation and expansion of our business and do not anticipate paying cash dividends on the common stock in the foreseeable future. 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.

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Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding Options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (1)
Equity compensation plans approved by security holders	4,355,320	(1) $	1.92	208,217
Equity compensation plans not approved by security holders	1,129,865	(2) $	1.64	
Total	5,485,185	$	1.86	208,217

(1) On May 26, 2004, we, as Reality Interactive, Inc., executed an Agreement and Plan of Merger with Natural Gas Systems, Inc., a Delaware corporation (the Merger). In connection with the Merger, we assumed the obligations of 600,000 stock options under our acquired subsidiary s 2003 Stock Option Plan. As of June 30, 2010, 470,000 shares remain issuable upon exercise of stock options under the 2003 Stock Option Plan and no further options shall be issued there under. As of June 30, 2011, there were 3,945,195 shares of common stock issuable upon exercise of outstanding stock options, 59,875 options that were exercised and 1,346,588 shares of common stock issued directly under the Amended and Restated 2004 Stock Plan, leaving 208,217 shares of common stock available for issuance.

(2) In addition to assuming certain obligations listed in footnote 1 above, in connection with the Merger, we also assumed outstanding warrants to purchase shares of common stock issued in connection with arranging the merger and in connection with capital raising. Total warrants outstanding as of June 30, 2011 related to these activities were 92,365 with a weighted average exercise price of $2.50. Also included were 1,037,500 warrants with a weighted average exercise price of $1.56 issued in connection with employment and or compensation arrangements, including a warrant to purchase 287,500 shares of common stock in connection with Mr. Herlin s employment agreement with the Company, a warrant to purchase 200,000 shares in connection with Mr. Mazzanti s employment agreement with the Company, a warrant to purchase 400,000 shares of common stock in connection with Mr. Herlin s annual performance incentives, including warrants in lieu of cash bonus, and a warrant to purchase 150,000 shares of common stock in connection with Mr. McDonald s annual performance incentives, including warrants in lieu of cash bonus.

Recent Sales of Unregistered Securities

On March 31, 2011, the Company sold 58,350 shares of common stock pursuant to a net cashless exercise of placement warrants. The placement warrants, issued to Laird Cagan, a member of our board of directors, in 2004 in connection with a financing transaction, gave Mr. Cagan the right to purchase 66,943 shares, with a weighted average exercise price of $1.00 per share. The shares of common stock were issued to Mr. Cagan pursuant to an exemption from registration afforded under Section 4(2) of the Securities Act of 1933.

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Item 6. Selected Financial Data

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

	Year Ended June 30				
	2011	2010	2009	2008	2007
Income Statement Data					
Revenues	$ 7,530,875	$ 5,021,901	$ 6,095,183	$ 4,256,128	$ 1,866,878
Lease operating expense	$ 1,298,650	$ 1,616,767	$ 1,281,989	$ 1,255,787	$ 1,352,907
Production taxes	$ 80,677	$ 48,312	$ 158,794	$ 90,252	$ 62,426
Depreciation, depletion, and amortization	$ 563,104	$ 1,818,110	$ 2,461,162	$ 903,214	$ 291,150
Accretion expense	$ 59,913	$ 61,054	$ 37,601	$ 20,196	$ 17,319
General and administrative expense (G&A) (excluding stock-based compensation)	$ 3,799,377	$ 2,943,843	$ 3,490,466	$ 3,705,751	$ 2,878,107
G&A: Stock-based compensation	$ 1,536,007	$ 2,148,400	$ 2,405,900	$ 1,791,486	$ 1,613,493
Gain from sale of oil and natural gas properties	$	$	$	$	$
Income (loss) from operations	$ 193,147	$ (3,614,585)	$ (3,740,729)	$ (3,510,558)	$ (4,348,524)
Interest income	$ 14,214	$ 55,054	$ 122,272	$ 854,130	$ 1,899,460
Income tax provision (benefit)	$ 448,914	$ (1,171,824)	$ (1,016,864)	$ (1,085,454)	$ (638,853)
Net loss	$ (241,553)	$ (2,387,707)	$ (2,601,593)	$ (1,570,974)	$ (1,810,211)
Earnings (loss) per common share - Basic	$ (0.01)	$ (0.09)	$ (0.10)	$ (0.06)	$ (0.07)
Earnings (loss) per common share - Diluted	$ (0.01)	$ (0.09)	$ (0.10)	$ (0.06)	$ (0.07)
Cash Flows Data					
Operating Activities:					
Before changes in operating assets and liabilities	$ 2,331,867	$ 877,914	$ 3,070,310	$ 3,740,878	$ (11,865,115)
Changes in operating assets and liabilities	723,249	1,467,267	2,884,468	(4,597,678)	(2,626,933)
Cash provided by (used in) operating activities	3,055,116	2,345,181	5,954,778	(856,800)	(14,492,048)
Investing Activities:					
Development of oil and natural gas properties	(2,509,652)	(3,280,425)	(8,063,465)	(11,187,291)	(417,964)
Acquisition of oil and natural gas properties	(997,279)	(517,530)	(2,603,098)	(8,789,501)	(1,918,757)
Proceeds from sale of oil and natural gas properties	231,326			4,452,450	155,378
Maturities of certificates of deposit	1,100,000	2,059,147			
Purchases of certificates of deposit		(1,350,000)	(1,757,312)		
Cash in qualified intermediary account for like-kind exchanges					34,662,368
Other	(49,566)	(13,220)	(33,350)	(93,596)	(120,050)
Cash provided by (used in) investing activities	(2,225,171)	(3,102,028)	(12,457,225)	(15,617,938)	32,360,975
Financing Activities:					

Purchase of treasury stock						(882,022)				
Payments on notes payable										
Proceeds from notes payable										
Equity transactions		106,077		3,342		130		76		(15,532)
Windfall tax benefits		173,157								
Other						3,823				
Cash provided by (used in) financing activities		279,234		3,342		(878,069)		76		(15,532)
Increase (decrease) in cash and cash equivalents	$	1,109,179	$	(753,505)	$	(7,380,516)	$	(16,474,662)	$	17,853,395

		June 30, 2011		June 30, 2010		June 30, 2009		June 30, 2008		June 30, 2007
Balance Sheet Data										
Total current assets	$	6,574,312	$	6,229,351	$	8,873,786	$	17,801,070	$	28,921,518
Total assets	$	40,168,425	$	37,195,075	$	37,828,823	$	40,365,848	$	34,905,992
Total current liabilities	$	2,428,404	$	1,287,699	$	1,237,904	$	4,171,048	$	1,596,558
Total liabilities	$	6,703,668	$	5,717,882	$	6,072,229	$	7,362,114	$	2,122,846
Stockholders equity	$	33,464,757	$	31,477,193	$	31,756,594	$	33,003,734	$	32,783,146
Common stock outstanding		27,612,916		27,061,376		26,530,317		26,870,439		26,776,234

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	Quarter Ended (unaudited)				
	June 30, 2011	March 31, 2011	December 31, 2010	September 30, 2010	June 30, 2010
Revenues					
Crude oil	$ 2,638,138	$ 1,607,521	$ 778,594	$ 648,218	$ 759,344
Natural gas liquids (NGLs)	224,062	228,050	231,495	209,918	231,460
Natural gas	303,072	181,504	169,343	310,960	368,387
Total operating revenues	3,165,272	2,017,075	1,179,432	1,169,096	1,359,191
Operating Expense					
Lease operating expense (LOE)	348,268	284,577	311,224	354,581	482,160
Production taxes	26,593	26,308	13,073	14,703	8,054
Depreciation, depletion, and amortization	204,141	132,516	102,429	124,018	144,766
Accretion expense	16,599	16,233	10,766	16,315	15,954
G&A (excluding stock-based compensation) (1)	966,676	966,628	912,993	953,081	433,064
G&A: Stock-based compensation (2)	392,593	392,533	396,394	354,486	957,595
Total operating expense	1,954,870	1,818,795	1,746,879	1,817,184	2,041,593
Operating income (loss)	1,210,402	198,280	(567,447)	(648,088)	(682,402)
Interest income, net	1,180	1,562	3,705	7,767	7,269
Net income (loss) before income tax benefit	1,211,582	199,842	(563,742)	(640,321)	(675,133)
Income tax (provision) benefit	(676,692)	(29,416)	102,207	154,987	245,712
Net income (loss)	$ 534,890	$ 170,426	$ (461,535)	$ (485,334)	$ (429,421)
Net income (loss) per share basic and diluted	$ 0.02	$ 0.01	$ (0.02)	$ (0.02)	$ (0.02)
Weighted average number of common shares outstanding					
Basic	27,612,916	27,521,957	27,457,118	27,160,723	27,137,611
Diluted	31,090,818	30,833,505	27,457,118	27,160,723	27,137,611
Sales volumes per day					
Oil (Bbls) - Delhi	219.6	148.1	68.1	49.5	62.9
Other properties					
Oil (Bbls)	36.3	36.4	33.5	45.2	46.7
NGL (Bbls)	44.9	50.4	54.6	55.1	64.2
Natural gas (Mcf)	822.8	513.6	505.5	771.8	972.7
Total (BOE)	438.0	320.4	240.4	278.5	335.8
Average sales price					
Oil per Bbl - Delhi	$ 115.25	$ 98.89	$ 84.42	$ 75.14	$ 76.48
Other properties					
Oil per Bbl	101.13	88.38	80.98	73.51	75.77
NGL per Bbl	54.88	50.31	46.12	41.41	39.63
Natural gas per Mcf	4.05	3.93	3.64	4.38	4.16
Total per BOE	79.42	69.94	53.32	45.63	44.47
Per BOE					
LOE and production taxes	9.41	10.78	14.66	14.41	16.04
DD&A	5.12	4.59	4.63	4.84	4.74
Accretion expense	0.42	0.56	0.49	0.64	0.52
G&A (excluding stock-based compensation)	24.25	33.52	41.28	37.20	14.17
G&A: Stock-based compensation	9.85	13.61	17.92	13.84	31.33
Total operating expense	49.05	63.06	78.98	70.93	66.80
Operating (loss) income	$ 30.37	$ 6.88	$ (25.65)	$ (25.30)	$ (22.33)
Net income (loss) before income taxes	$ 30.40	$ 6.93	$ (25.49)	$ (24.99)	$ (22.09)

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(1) **Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations**

Executive Overview

General

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

We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain control of our assets for the benefit of our shareholders, including approximately 20% 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.

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

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

We expect to fund our base fiscal 2012 development plan from working capital, with any increases to the base plan funded out of working capital, net cash flows from our properties in the Giddings and Delhi Fields and appropriate financing vehicles, including possible additional issuances of our Series A perpetual non-convertible preferred stock.

Highlights for our fiscal year 2011

Oil & Gas Reserves

- **Proved reserves increased 1.43 million BOE, or 12%, while PV-10 increased 41%.** The increase in proved reserves is primarily due to an acceleration of our Delhi payout date, estimated by D&M to occur at calendar year end 2013, versus last year s report estimate of mid-2016. Acceleration of the payout date is primarily due to improved operating performance and higher oil prices. The increase in PV-10 is primarily due to higher oil prices, the increased reserves and the accelerated date of deemed payout.

- **Proved developed reserves increased 333%.** The increase in proved developed reserves is primarily due to continued investment by the operator in the Delhi Field, combined with improved production performance. Proved developed reserves are now 39% of total proved reserves.

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• **The improvement in proved and proved developed reserves did not materially affect our high oil content**. Our proved reserves are 84% oil and 5% gas liquids, compared to 83% and 9%, respectively, the previous year.

	Proved			Probable		
	2011	2010	Change	2011	2010	Change
Reserves MMBOE	13.8	12.4	11%	6.3	7.2	(12)%
% Developed	39%	9%	333%	27%	5%	440%
Liquids %	89%	92%		100%	89%	
(In millions)						
PV-10*	$375	$266	41%	$76	$64	19%
PV-10 Spot	$434	$252	72%	$92	$61	51%
PV-10 Strip	$472	$308	53%	$101	$77	31%

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

Projects

• **Delhi.** D&M s independent reserve report for our Delhi interests reflects an acceleration of the reversionary working interest payout date to late calendar 2013, more than two years earlier than projected in their June 30, 2010 report. The acceleration is due primarily to a lower rate of CO_2 purchases, improved performance and higher realized oil price. The same factors resulted in an increase of 1.57 MMBO of net proved reserves primarily associated with the reversionary working interest. Proved developed reserves at Delhi increased from 7% of total proved reserves to 45% of total proved reserves, due to continued investment by the operator and improved performance in the field. Production continues to increase as Phase II was implemented through first CO2 injection in late December 2010 and first oil production response in March 2011. Gross and net oil production increased 48% to 2,964 gross (219 net) barrels of oil per day during the fourth fiscal quarter of 2011 from 2,003 gross (148 net) barrels of oil per day in the preceding third fiscal quarter, and increased 248% from the fourth fiscal quarter ending June 30, 2010, the first full quarter of EOR production. Both Phases I and II resulted in oil production response 3-4 months earlier than projected.

Meanwhile, Phase III is currently under construction and related CO2 injection is expected during calendar 2011. Up to six phases are ultimately expected, with Phase I being approximately half the size of all other phases. To date, the operator has reported expending $383 million on the project, which has no effect on our deemed $200 million reversionary payout amount. Gross production averaged more than 1,634 gross (121 net) barrels per day for fiscal year 2011, compared to less than 231 gross (17 net) barrels per day during fiscal 2010. Our net production currently is from our 7.4% royalty interest and is free and clear of all cost, except for a pipeline transportation tariff of less than $2.00 per barrel. Our realized oil price at Delhi tracks Louisiana Light Sweet oil price, which has been similarly tracking Brent crude oil price during the last half of 2011. As an example, our realized Delhi oil price of $106 in June 2011 was a $14 premium over the price we realized in our properties in the Giddings Field.

The factors that impacted our proved reserves also increased our proved PV-10 by 41% to $375 million and our probable PV-10 by 19% to $76 million. Due to the accelerated reversion date, we now expect to bear approximately $12.7 million of capital expenditures in calendar 2014, compared to the year ago projection of no capital expenditures related to our proved reserves. At reversion, our net revenue interest will increase from 7.4% to 26.5%, and we will begin bearing 23.9% of all costs.

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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.

- **Due to continued production testing during 2011, we have elected to restore proved reserves for our properties in the Lopez Field in South Texas (Neptune Project).** Previously, we had elected to downgrade our reserves in the Lopez Field due to difficulties and delays in creating adequate water injection capacity needed to adequately test production. This problem was alleviated in the first half of fiscal 2011 and the resulting stable production demonstrated that proved reserves and expanded field development are warranted. Consequently, our independent reservoir engineer has assigned 61 MBO of proved oil reserves to one producing well and five drilling locations, and 378 MBO of probable oil reserves to 36 drilling locations. Associated PV-10 is $470 thousand for proved reserves and $3.2 million for probable reserves.

- **In Giddings, our production of 72 MBOE was more than offset by 331 MBOE of positive proved reserve revisions.** Sales of reserves in place totaling 522 MBOE resulted in a 9% reduction in proved reserves to 2,720 MBOE. During 2011, we drilled and completed three producing wells through our industry joint venture. One well far exceeded expectations, one well underperformed and one well was not commercially productive in the target horizon and was subsequently recompleted into another reservoir. In aggregate, we believe that the three wells are expected to approach combined expected recovery. Based on drilling results and natural gas prices, we highgraded our portfolio of remaining proved drilling locations to the current thirteen total.

- **Our unconventional gas project is now focused on our Haskell County, OK leasehold.** During the latter part of fiscal 2011, we commenced our first test in Haskell County, OK through a re-entry. During operations to create a salt water disposal zone, we encountered natural gas. We subsequently revised our project to test this zone with a single stage of hydraulic fracturing. We are currently producing the well to determine economic viability of further field development of this zone. Our independent reservoir engineer has assigned proved reserves to this one gross and 0.55 net producing well and five gross and 1.34 net drilling locations totaling 768 MMCF.

- We continued production testing of one shallow Woodford well in our Wagoner County, OK leasehold during the early portion of fiscal 2011. Based on the results to date, combined with the natural gas market and requirement for substantial infrastructure, we have determined that our other projects offer more value potential and thus have elected to divest our Wagoner County assets. Therefore, no reserves for Wagoner County have been included in our reported reserves.

Operations

- **Our fiscal 2011 net loss declined 90% to $242,000, compared to fiscal 2010 s $2.4 million loss.** The year ended on a positive note with net income of $535,000 and $170,000 in FQ4 and FQ3, respectively.

- **Revenues in fiscal 2011 increased 50% to $7.5 million, compared to $5 million in fiscal 2010, primarily due to a 95% increase in oil volumes and 33% increase in oil prices, partially offset by a 39% decrease in NGL and natural gas volumes.** .

- **Operating costs in fiscal 2011 decreased $1.3 million to $7.3 million, a 15% decrease from fiscal 2010, primarily due to a 68% reduction in our annual depletion rate to $4.55 per BOE.** Our depletion rate for FQ4 was $4.92 per BOE due to the inclusion of net capital expenditures associated with the last phase of our Delhi EOR project resulting from the currently projected two year acceleration in payout. We have not, to date, experienced a ceiling test write down of our oil and gas property costs, therefore our depletion rate is a proxy for our historic finding and development costs.

- **Non-cash, stock-based compensation expense of $1.5 million comprised over 28% of general and administrative expense for fiscal 2011.** Non-cash, stock-based compensation expense remains an important part of our total compensation program, as a small company in competition for talented staff with numerous, more established other companies, to help motivate and retain high performing employees and consultants, in addition to conserving our cash resources.

For further details, see Results of Operations below.

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Finances

- **We ended the year with $4.1 million of working capital, compared to $4.9 million at June 30, 2010.** At June 30, 2011, working capital included $4.5 million of cash, cash equivalents and short-term certificates of deposit. The $0.8 million reduction in our working capital since June 30, 2010 was due primarily to capital investments of $3.4 million in oil and natural gas properties, mostly offset by positive cash flow generated from our oil and gas properties.

- **Cash flows from operations covered our general and administrative expenses and funded most of our capital expenditures.** Cash flows from operations were $3.1 million during the year ended June 30, 2011, which includes $1.0 million received in February 2011 from the Internal Revenue Service as a result of a carry-back of our tax loss for the year ended June 30, 2010.

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

Looking forward into 2012

We currently expect to be more active during fiscal 2012 in the Giddings Field, Haskell County, Lopez Field and artificial lift technology projects. Expanded development drilling in the first three projects will be funded from working capital, expected cash flows from operations and future joint ventures currently in discussion. Activity is intended to further our goal of maturing projects outside of Delhi and derisking their future capital investment and associated production. At the same time, we expect production at Delhi to continue to increase as Phase II matures and Phase III is put into operation through incremental CO2 injection.

Our base case capital budget of up to $12 million will be primarily focused on:

- Continued development drilling of our higher valued locations in the Giddings Field
- Initial development rollout in the Lopez Field in South Texas with two oil producers and two injectors
- Projected initial development of the Woodford Shale in Haskell County, OK
- Demonstrations of GARP, our artificial lift technology for other operators
- Maintenance of leases on our higher valued drilling locations and Haskell County leasehold and expansion of our Lopez Field leasehold as warranted

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

Continued conservative financial management.

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

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

- **Utilize joint ventures, project financing and/or preferred stock issuances to accelerate project development.** We may accelerate our development operations where warranted by utilizing joint ventures, project financing, selective divestments of noncore assets or continued issuance of our preferred stock at an attractive valuation. In early July we raised $5.1 million of gross proceeds before offering expenses through an offering of 220,000 shares of 8.5% Series A Preferred Stock. These shares are perpetual, nonconvertible and redeemable by the company at the $25 per share liquidation value after three years, or earlier at a premium to the liquidation value in the event of a change in control. We continue to sell up to an additional 180,000 shares through at the market transactions, which to date have been at a premium to the liquidation value of $25 per share.

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

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Liquidity and Capital Resources

At June 30, 2011, our working capital was $4.1 million and we continued to be debt free. This compares to working capital of $4.9 million at June 30, 2010. The $0.8 million decrease in working capital since June 30, 2010, was due primarily to investments of $3.4 million in oil and natural gas properties, offset by an asset sale of $0.2 million and positive operating cash flows. Of the $3.4 million of capital expenditures incurred during our fiscal year ended June 30, 2011, $1.0 million was for leasehold acquisitions and $2.4 million was for development activities. Development activities were primarily in the Giddings Field in Texas and our unconventional gas project in Eastern Oklahoma.

Cash Flows from Operating Activities

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

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

Cash Flows from Investing Activities

Cash paid for oil and gas capital expenditures during our fiscal year ended June 30, 2011 and 2010, was $3.5 million and $3.8 million, respectively, which includes net payments on accounts payable of $0.1 million during both periods, relating to expenditures for oil and natural gas properties. During the year ended June 30, 2011, we received $0.2 million for a lease sale in the Giddings Field.

During the year ended June 30, 2011, $1.1 million of certificates of deposit matured. During the year ended June 30, 2010, we purchased $1.4 million in short-term certificates of deposit and $2.1 million of certificates of deposit matured.

Cash Flows from Financing Activities

During the year ended June 30, 2011, we received $0.1 million due to the exercise of stock options and $0.2 million for windfall tax benefit received in 2010. There were no significant cash flows from financing activities during the year ended June 30, 2010.

Capital Budget

For our fiscal 2012 Plan, we expect to incur capital expenditures of up to 12 million (for expenditure details, see the Looking Forward section above).

We expect to fund our fiscal 2012 Plan with internally generated funds, our working capital and future joint ventures. Increases in our activity level over the planned operations will be funded from working capital, joint ventures, project financing, selective divestments of noncore assets or from additional sales of our 8.5% Preferred Stock.

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Results of Operations

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

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

	Year Ended June 30 2011	2010	Variance	% change
Sales Volumes, net to the Company:				
Delhi crude oil Royalty (Bbl)	44,141	6,333	37,808	597%
Other properties				
Crude oil (Bbl)	13,824	23,416	(9,592)	(41)%
NGLs (Bbl)	18,704	27,820	(9,116)	(33)%
Natural gas (Mcf)	238,608	407,674	(169,066)	(41)%
Crude oil, NGLs and natural gas (BOE)	116,437	125,515	(9,078)	(7)%
Revenue data:				
Delhi crude oil	$ 4,493,240	$ 485,032	$ 4,008,208	826%
Other properties				
Crude oil	1,179,231	1,703,227	(523,996)	(31)%
NGLs	893,525	1,079,383	(185,858)	(17)%
Natural gas	964,879	1,754,259	(789,380)	(45)%
Total revenues	7,530,875	5,021,901	$ 2,508,974	50%
Average price:				
Delhi crude oil	$ 101.79	$ 76.59	$ 25.20	33%
Other properties				
Crude oil (per Bbl)	85.30	72.74	12.56	17%
NGLs (per Bbl)	47.77	38.80	8.97	23%
Natural gas (per Mcf)	4.04	4.30	(0.26)	(6)%
Crude oil, NGLs and natural gas (per BOE)	$ 64.68	$ 40.01	$ 24.67	62%
Expenses (per BOE)				
Lease operating expenses and production taxes	$ 11.85	$ 13.27	$ (1.42)	(11)%
Depletion expense on oil and natural gas properties (a)	$ 4.55	$ 14.10	$ (9.55)	(68)%

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

Net loss. For the year ended June 30, 2011, we reported a net loss of $241,553, or $0.01 loss per share (which includes $1,536,007 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $7,530,875. This compares to a net loss of $2,387,707, or $0.09 loss per share (which includes $2,148,400 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $5,021,901 for the year ended June 30, 2010. The decrease in net loss was primarily due to an increase in our revenues of $2,508,974 and a decrease in operating costs of $1,298,758 (primarily related to a decrease in depreciation, depletion, and amortization). Additional details of the components of net loss are explained in greater detail below.

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

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

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

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

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

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

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

Depreciation, Depletion & Amortization Expense (DD&A). DD&A decreased by 69% to $563,104 for year ended June 30, 2011, compared to $1,818,110 for the year ended June 30, 2010. The decrease is primarily due to a 7% decrease in net sales volumes, and a lower annual depletion rate ($4.55 vs. $14.10) per BOE.

Our depletion rate decreased significantly in the fourth quarter of fiscal year 2010, when we first recorded reserves at Delhi of 9.4 million proved oil reserves with associated legacy costs of only $1.2 million transferred to our full cost pool.

Interest Income. Interest income for the year ended June 30, 2011 decreased $40,840 to $14,214, compared to $55,054 for the year ended June 30, 2010. The decrease in interest income is due to lower average daily balances of cash and short term certificates of deposit and a reduction in market interest rates received on invested cash.

Inflation. Although the general inflation rate in the United States, as measured by the Consumer Price Index and the Producer Price Index, has been relatively low in recent years, the oil and gas industry has experienced unusually volatile price movements in commodity prices, vendor goods and oilfield services. Prices for drilling and oilfield services, oilfield equipment, tubulars, labor, expertise and other services greatly impact our lease operating expenses and our capital expenditures. During fiscal 2009 and into fiscal 2010, we saw a substantial decline in both petroleum product prices and drilling and oilfield services costs from prior years, followed more recently by moderate increases in products and services, particularly drilling rig and hydraulic fracturing rates. Product prices, operating costs and development costs may not always move in tandem.

Known Trends and Uncertainties. General worldwide economic conditions continue to be uncertain and volatile. Concerns over uncertain future economic growth are affecting numerous industries, companies, as well as consumers, which impact demand for crude oil and natural gas. If demand decreases in the future, it may put downward pressure on crude oil and natural gas prices, thereby lowering our revenues and working capital going forward.

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

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Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2011, we are obligated to make under our contractual obligations and commitments. We expect to fund these contractual obligations with cash on hand and cash generated from operations.

	Payments Due by Period (In Thousands)				
	Total	Less than 1 Year	1 3 Years	4 5 Years	After 5 Years
Contractual Obligations					
Operating lease	806,563	157,268	318,022	318,022	13,251
Other Obligations					
Asset retirement obligations	859,586				859,586
Total obligations	$ 1,666,149	$ 157,268	$ 318,022	$ 318,022	$ 872,837

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost accounting method for our oil and natural gas properties as prescribed by SEC Regulation S-X Rule 4-10. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. Costs are transferred to the full cost pool as the properties are evaluated. As of June 30, 2011, our total unevaluated costs were $2.9 million. If these costs were evaluated and included in our full cost pool, with no increases in our proved reserves as of June 30, 2011, our depreciation, depletion and amortization expense would have increased by approximately $9,000.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense, and the estimated future net cash flows associated with those proved reserves is the basis in determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, additional development activity, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare our reserve estimates, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and / or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves, affecting our quarterly ceiling test calculation and could significantly affect our depletion rate. A 10% decrease in commodity prices used to determine our proved reserves and Standardized Measure as of June 30, 2011, would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in the Company s proved reserve estimate at June 30, 2011 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $11,000, $23,000, and $36,000, respectively.

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

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Valuation of Deferred Tax Assets. We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared or filed; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carry backs and carry forwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our net operating loss). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of June 30, 2011, we have recorded a valuation allowance for the portion of our net operating loss that is limited by IRS Section 382.

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

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

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements as of June 30, 2011.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Interest Rate Risk

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

Commodity Price Risk

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

Item 8. Financial Statements

Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Evolution Petroleum Corporation

Houston, Texas

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2011 and 2010, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended June 30, 2011. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Evolution Petroleum Corporation and subsidiaries as of June 30, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended June 30, 2011, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Evolution Petroleum Corporation and subsidiaries internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated September 13, 2011 expressed an unqualified opinion on the effectiveness of Evolution Petroleum Corporation s internal control over financial reporting.

/s/ Hein & Associates LLP
Houston, Texas
September 13, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Evolution Petroleum Corporation

Houston, Texas

We have audited Evolution Petroleum Corporation s internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Evolution Petroleum Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Evolution Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2011 and 2010, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended June 30, 2011, and our report dated September 13, 2011, expressed an unqualified opinion.

/s/ Hein & Associates LLP
Houston, Texas
September 13, 2011

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2011	June 30, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 4,247,438	$ 3,138,259
Certificates of deposit	250,000	1,350,000
Restricted cash from joint interest partner	118,194	
Receivables		
Oil and natural gas sales	1,559,404	536,366
Joint interest partner	86,105	
Income taxes	28,680	25,200
Other	167	147,059
Income taxes recoverable		716,973
Prepaid expenses and other current assets	284,324	315,494
Total current assets	6,574,312	6,229,351
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties full-cost method of accounting, of which $2,940,199 and $7,851,068 at June 30, 2011 and 2010, respectively, were excluded from amortization.	33,447,564	30,803,061
Other property and equipment	69,262	101,998
Total property and equipment	33,516,826	30,905,059
Other assets	77,287	60,665
Total assets	$ 40,168,425	$ 37,195,075
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 514,177	$ 678,609
Joint interest advances	105,567	
Accrued payroll	682,850	75,692
Royalties payable	742,651	221,062
State and federal taxes payable	298,594	202,334
Other current liabilities	84,565	110,002
Total current liabilities	2,428,404	1,287,699
Long term liabilities		
Deferred income taxes	3,330,266	2,949,880
Asset retirement obligations	859,586	811,635
Stock-based compensation		587,033
Deferred rent	85,412	81,635

Total liabilities		6,703,668		5,717,882
Commitments and contingencies (Note 12)				
Stockholders equity				
Preferred stock, par value $0.001; 5,000,000 shares authorized; no shares issued or outstanding				
Common stock; par value $0.001; 100,000,000 shares authorized; issued 28,401,116 shares; outstanding 27,612,916 shares and 27,061,376 shares as of June 30, 2011 and 2010, respectively.		28,400		27,849
Additional paid-in capital		20,761,209		18,532,643
Retained earnings		13,557,170		13,798,723
		34,346,779		32,359,215
Treasury stock, at cost, 788,200 shares as of June 30, 2011 and June 30, 2010.		(882,022)		(882,022)
Total stockholders equity		33,464,757		31,477,193
Total liabilities and stockholders equity	$	40,168,425	$	37,195,075

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Year Ended June 30, 2011	2010	2009
Revenues			
Crude oil	$ 5,672,471	$ 2,188,259	$ 2,747,494
Natural gas liquids	893,525	1,079,383	1,625,063
Natural gas	964,879	1,754,259	1,722,626
Total Revenues	7,530,875	5,021,901	6,095,183
Operating Costs			
Lease operating expenses	1,298,650	1,616,767	1,281,989
Production taxes	80,677	48,312	158,794
Depreciation, depletion and amortization	563,104	1,818,110	2,461,162
Accretion of asset retirement obligations	59,913	61,054	37,601
General and administrative expenses *	5,335,384	5,092,243	5,896,366
Total operating costs	7,337,728	8,636,486	9,835,912
Income (loss) from operations	193,147	(3,614,585)	(3,740,729)
Other income			
Interest income	14,214	55,054	122,272
Net income (loss) before income tax (provision) benefit	207,361	(3,559,531)	(3,618,457)
Income tax (provision) benefit	(448,914)	1,171,824	1,016,864
Net loss	$ (241,553)	$ (2,387,707)	$ (2,601,593)
Loss per common share			
Basic and Diluted	$ (0.01)	$ (0.09)	$ (0.10)
Weighted average number of common shares outstanding			
Basic and Diluted	27,437,496	27,004,066	26,461,057

*General and administrative expenses for the year ended June 30, 2011, 2010 and 2009 included non-cash stock-based compensation expense of $1,536,007, $2,148,400 and $2,405,900, respectively.

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flow

	Year Ended June 30, 2011	2010	2009
Cash Flows From Operating Activities			
Net loss	$ (241,553)	$ (2,387,707)	$ (2,601,593)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	563,104	1,818,110	2,461,162
Stock-based compensation	1,536,007	2,148,400	2,405,900
Issuance of common stock for charitable donation			28,600
Accretion of asset retirement obligations	59,913	61,054	37,601
Settlement of asset retirement obligations	(1,847)		(90,761)
Deferred income taxes	380,386	(771,437)	819,388
Deferred rent	3,777	3,777	3,777
Other	32,080	5,717	6,236
Changes in operating assets and liabilities:			
Receivables from oil and natural gas sales	(1,023,038)	(4,048)	1,533,982
Receivables from income taxes and other	687,228	1,512,041	1,963,436
Due from joint interest partner	(87,743)		
Prepaid expenses and other current assets	31,170	(153,053)	108,497
Accounts payable and accrued expenses	497,783	65,144	(624,333)
Royalties payable	521,589	2,585	(254,850)
Income taxes payable	96,260	44,598	157,736
Net cash provided by operating activities	3,055,116	2,345,181	5,954,778
Cash Flows from Investing Activities			
Proceeds from asset sales	231,326		
Development of oil and natural gas properties	(2,509,652)	(3,280,425)	(8,063,465)
Acquisitions of oil and natural gas properties	(997,279)	(517,530)	(2,603,098)
Capital expenditures for other equipment	(864)		(28,635)
Maturities of certificates of deposit	1,100,000	2,059,147	
Purchases of certificates of deposit		(1,350,000)	(1,757,312)
Other assets	(48,702)	(13,220)	(4,715)
Net cash used in investing activities	(2,225,171)	(3,102,028)	(12,457,225)
Cash Flows from Financing Activities			
Proceeds from issuance of restricted stock	28	42	130
Proceeds from the exercise of stock options	106,049	3,300	
Windfall tax benefit	173,157		
Purchase of treasury stock			(882,022)
Other			3,823
Net cash provided by (used in) financing activities	279,234	3,342	(878,069)
Net increase (decrease) in cash and cash equivalents	1,109,179	(753,505)	(7,380,516)
Cash and cash equivalents, beginning of period	3,138,259	3,891,764	11,272,280
Cash and cash equivalents, end of period	$ 4,247,438	$ 3,138,259	$ 3,891,764

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity

For the Years ended June 30, 2011, 2010 and 2009

	Common Stock		Additional Paid-in	Retained	Treasury	Total Stockholders
	Shares	Par Value	Capital	Earnings	Stock	Equity
Balance, July 1, 2008	26,870,439	$ 26,870	$ 14,188,841	$ 18,788,023	$	$ 33,003,734
Issuance of common stock to certain employees in lieu of partial payment of 2008 cash bonus	46,795	47	168,415			168,462
Issuance of restricted common stock	390,283	390	(260)			130
Issuance of common stock for charitable donation	11,000	11	28,589			28,600
Purchase of 788,200 treasury shares	(788,200)				(882,022)	(882,022)
Other			3,823			3,823
Stock-based compensation			2,035,460			2,035,460
Net loss				(2,601,593)		(2,601,593)
Balance, June 30, 2009	26,530,317	$ 27,318	$ 16,424,868	$ 16,186,430	$ (882,022)	$ 31,756,594
Issuance of common stock to certain employees in lieu of cash payment of 2009 bonus	138,224	138	370,302			370,440
Issuance of restricted common stock	386,914	387	(345)			42
Exercise of stock warrants	133,005	133	(133)			
Exercise of stock options	3,000	3	3,297			3,300
Forfeiture of restricted common stock	(130,084)	(130)	130			
Windfall tax benefit			173,157			173,157
Stock-based compensation			1,561,367			1,561,367
Net loss				(2,387,707)		(2,387,707)
Balance, June 30, 2010	27,061,376	$ 27,849	$ 18,532,643	$ 13,798,723	$ (882,022)	$ 31,477,193
Issuance of common stock to certain employees in lieu of cash payment of 2010 bonus	106,927	107	586,926			587,033
Issuance of restricted common stock	303,603	303	(275)			28
Exercise of stock warrants	58,350	58	(58)			
Exercise of stock options	86,875	87	105,962			106,049
Forfeiture of restricted common stock	(4,215)	(4)	4			
Stock-based compensation			1,536,007			1,536,007
Net loss				(241,553)		(241,553)
Balance, June 30, 2011	27,612,916	28,400	20,761,209	13,557,170	$ (882,022)	33,464,757

See accompanying notes to consolidated financial statements.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Basis of Preparation

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

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

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

Note 2 Summary of Significant Accounting Policies

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

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivables if it is determined that collection of all or a part of an outstanding balance is not probable. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2011 and 2010, no allowance for doubtful accounts was considered necessary.

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

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

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the Ceiling Test). If the capitalized cost of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes (the Net Capitalized Costs), exceed the Ceiling , this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent, and assuming continuation of existing economic

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 2 Summary of Significant Accounting Policies (Continued)

conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices determined as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. Our Ceiling Test did not result in an impairment of our oil and natural gas properties during the years ended June 30, 2011, 2010 and 2009.

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

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

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

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

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

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

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

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 2 Summary of Significant Accounting Policies (Continued)

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

Note 3 Recent Accounting Pronouncements

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

Updates to Oil and Gas Accounting Rules. In January 2010, the FASB issued its updates to oil and gas accounting rules to align the oil and gas reserve estimation and disclosure requirements of Extractive Industries Oil and Gas with the requirements in the SEC s final rule, *Modernization of the Oil and Gas Reporting Requirements,* which was issued on December 31, 2008. We adopted the new rules effective June 30, 2010. The new rules are applied prospectively as a change in estimate. Adoption of these requirements did not significantly impact our reported reserves or our consolidated financial statements. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology. Revised requirements in the final rule include, but are not limited to:

- Oil and gas reserves must be reported using the average price over the prior 12-month period, rather than year-end prices;
- Companies are allowed to report, on an optional basis, probable and possible reserves;
- Non-traditional reserves, such as oil and gas extracted from coal and shales, are included in the definition of oil and gas producing activities ;

- Companies are permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;

- Companies are required to disclose, in narrative form, additional details on their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs;

- Companies are required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4 Property and Equipment

As of June 30, 2011 and June 30, 2010 our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2011	June 30, 2010
Oil and natural gas properties		
Property costs subject to amortization	$ 35,860,517	$ 27,775,641
Less: Accumulated depreciation, depletion, and amortization	(5,353,152)	(4,823,648)
Unproved properties not subject to amortization	2,940,199	7,851,068
Oil and natural gas properties, net	$ 33,447,564	$ 30,803,061
Other property and equipment		
Furniture, fixtures and office equipment, at cost	261,340	260,476
Less: Accumulated depreciation	(192,078)	(158,478)
Other property and equipment, net	$ 69,262	$ 101,998

Unproved properties not subject to amortization includes unevaluated acreage of $2.2 and $6.0 million as of June 30, 2011 and June 30, 2010, respectively, consisting of properties in the Woodfood Shale trend in Oklahoma as of June 30, 2011 and properties in the Giddings Field in Central Texas, the Woodford Shale trend in Oklahoma, and the Lopez Field in South Texas (our Neptune Oil Project) as of June 30, 2010. Unproved properties include $0.7 as of June 30, 2011 and 2010, of participating interests through royalty and overriding royalty interests aggregating 7.4% in the Delhi Holt Bryant Unit of the Delhi Field in Louisiana and a 23.9% after payout reversionary working interest in the Delhi Holt Bryant Unit along with a 23.9% working interest in certain other depths in the Delhi Field. Unproved properties as of June 30, 2010, also include $1.2 million related to the drilling of three test wells and re-entry of four test wells on our acreage in Wagoner County in Oklahoma. Our evaluation of impairment of unproved properties occurs, at a minimum, on a quarterly basis.

The following table provides a summary of costs that are not being amortized as of June 30, 2011, by the fiscal year in which the costs were incurred:

		During the Year Ended June 30,				
Costs excluded from amortization	**Total**	**2011**	**2010**	**2009**	**2008**	**2007**
Leasehold acquisition costs and other	$ 2,195,194	$ 528,418	$	$ 141,365	$ 1,268,433	$ 256,978
Royalty and overriding royalty interests	745,005	9,378		3,636		731,991
	$ 2,940,199	$ 537,796	$	$ 145,001	$ 1,268,433	$ 988,969

Note 5 Asset Retirement Obligations

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following is a reconciliation of the beginning and ending asset retirement obligation for the years ended June 30, 2011 and 2010:

	Year Ended	
	2011	**2010**
Asset retirement obligations beginning of period	$ 811,635	$ 664,710
Liabilities incurred	15,000	85,871
Liabilities settled	(1,847)	
Accretion	59,913	61,054
Revisions to previous estimates	(25,115)	
Asset retirement obligations end of period	$ 859,586	$ 811,635

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 6 Stockholders Equity

On August 19, 2008, the Board of Directors authorized the issuance of 46,795 shares of common stock to certain employees who elected to receive these shares in lieu of a portion of their fiscal 2008 cash bonus. The value of the shares issued was $168,462, based on the fair market value on the date of issuance, or $3.60 per share.

On October 30, 2008, we repurchased 788,200 shares of our common stock at an average price of $1.10 per share, plus approximately $15,000 of transaction costs, from an unaffiliated accredited investor. There is currently no plan to repurchase additional common shares.

On December 9, 2008, three outside directors each received 30,000 shares of restricted common stock, with a per share price of $1.20, as part of their board compensation for calendar 2009. The value of the shares issued was $108,000, based on the fair market value on the date of issuance, or $1.20 per share. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors.

On January 16 and February 10, 2009, we issued 24,324 and 15,789 shares of restricted common stock, respectively, to a director as compensation for his services for calendar year 2009. The 15,789 share award was elected by the director in lieu of cash retainers for his board service during calendar 2009. The value of the shares issued was $60,000, based on the fair market value on the date of issuance. These issuances of common stock are subject to vesting terms per the individual stock agreements, which is generally one year for directors.

On May 29, 2009, we issued 11,000 shares of unregistered common stock to various non-profit entities as a charitable donation. We recognized an expense of $28,600 based on the per share price of $2.60 on the date of issue. These shares of common stock are subject to restrictions on transfer and cannot be sold until registered or the earlier of April 17, 2014, or written release by a duly appointed officer of the Company.

On June 19, 2009, pursuant to an offer by the Company as discussed in Note 7, we issued 260,170 shares of restricted common stock to certain employees in exchange for stock options to purchase 449,390 shares of common stock with a weighted average exercise price of $4.67. See Note 7.

On September 8, 2009, the Board of Directors authorized and the Company issued 138,224 unrestricted and fully vested shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2009 bonuses. The value of the shares issued was $370,440, based on the fair market value on the date of issuance, or $2.68 per share. The amount of bonus was accrued as of June 30, 2009 and recognized as a long-term liability. On September 8, 2009, when the shares were issued, the liability was reclassified to stockholders equity. See Note 7.

On September 8, 2009, the Board of Directors authorized and the Company issued 324,597 shares of restricted common stock from the 2004 Stock Plan to employees as a long-term incentive award. Total unrecognized stock-based compensation expense of $869,917 related to the long-term incentive award will be recognized ratably over a four year vesting period. See Note 7.

On October 27, 2009, 119,795 shares of common stock were issued through a net cashless exercise of a placement warrant. The placement warrant, which was issued to Cagan McAfee Capital Partners, LLC (CMCP), a related party (See Note 10), on May 26, 2004 in connection with a financing transaction, gave CMCP the right to purchase 165,000 shares, with an exercise price of $1.00 per share.

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

On December 9, 2009, a total of 42,317 shares of restricted common stock were issued to four outside directors as part of their board compensation for calendar year 2010. The value of the shares issued was $168,000, based on the fair market value on the date of issuance. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors. See Note 7.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 6 Stockholders Equity (Continued)

On February 6, 2010, a total of 38,182 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $187,965. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 7.

On March 5, 2010, a total of 20,000 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $90,000, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 7.

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

On June 14, 2010, an employee of the Company exercised 3,000 stock options granted in 2005 at an exercise price of $1.10. See Note 7.

On June 19, 2010, a total of 91,902 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $436,522. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 7.

On July 2, 2010, an employee of the Company exercised 6,875 stock options granted in 2007 at an exercise price of $2.33 per share. See Note 7.

On July 2, 2010, a total of 4,215 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $11,621. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 7.

On August 9, 2010, a total of 30,233 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $156,000, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 7.

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

On September 10, 2010, the Board of Directors authorized and the Company issued 240,478 shares of restricted common stock from the 2004 Stock Plan to certain employees as a long-term incentive award. Total unrecognized stock-based compensation expense of $1,320,224 related to the long-term incentive award will be recognized ratably over a four year period as the restricted common stock vests. See Note 7.

On October 1, 2010, a total of 4,845 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $29,118, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 7.

On December 9, 2010, a total of 28,047 shares of restricted common stock was issued to four outside directors as part of their board compensation for calendar year 2011. The value of the shares issued was $168,000, based on the fair market value on the date of issuance. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors. See Note 7

On December 21, 2010, an employee of the Company exercised 30,000 stock options granted in 2003 at an exercise price of $0.001 per share. See Note 7.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 6 Stockholders Equity (Continued)

On February 28, 2011, a former consultant of the Company exercised 50,000 stock options granted in 2005 at an exercise price of $1.80 per share. See Note 7.

On March 31, 2011, 58,350 shares of common stock were issued through a net cashless exercise of placement warrants. The placement warrants, which were issued to Laird Cagan, a related party (See Note 10), in 2004 in connection with a financing transaction, gave Mr. Cagan the right to purchase 66,943 shares, with a weighted average exercise price of $1.00 per share.

Note 7 Stock-Based Incentive Plan

We may grant option awards to purchase common stock (the Stock Options), restricted common stock awards (Restricted Stock), and unrestricted fully vested common stock, to employees, directors, and consultants of the Company and its subsidiaries under the Natural Gas Systems Inc. 2003 Stock Plan (the 2003 Stock Plan) and the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the 2004 Stock Plan or together, the EPM Stock Plans). Option awards for the purchase of 600,000 shares of common stock were issued under the 2003 Stock Plan. The 2004 Stock Plan authorized the issuance of 5,500,000 shares of common stock. No shares are available for grant under the 2003 Stock Plan and 208,217 shares remain available for grant under the 2004 Stock Plan as of June 30, 2011.

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

Short-term Incentive Compensation

On September 8, 2009, the Board of Directors authorized the issuance of 138,224 shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2009 bonuses in lieu of cash. The value of the shares issued was $370,440, based on the fair market value on the date of issuance, or $2.68 per share. The amount of bonus was accrued as of June 30, 2009, and recognized as a long term liability. On September 8, 2009, the liability was reclassified as additional paid-in capital.

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

Stock Options and Incentive Warrants

Non-cash stock-based compensation expense related to Stock Options and Incentive Warrants for the years ended June 30, 2011, 2010 and 2009 was $715,027, $985,060 and $1,786,055, respectively.

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

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7 Stock-Based Incentive Plan (Continued)

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

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

The following summary presents information regarding outstanding Stock Options and Incentive Warrants as of June 30, 2011, and the changes during the fiscal year:

	Number of Stock Options and Incentive Warrants		Weighted Average Exercise Price		Aggregate Intrinsic Value (1)	Weighted Average Remaining Contractual Term (in years)
Stock Options and Incentive Warrants outstanding at July 1, 2010	5,482,820	$	1.83			
Granted						
Exercised	(86,875)	$	1.22			
Cancelled or forfeited	(3,125)	$	2.33			
Expired						
Stock Options and Incentive Warrants outstanding at June 30, 2011	5,392,820	$	1.85	$	28,354,726	4.4
Vested or expected to vest at June 30, 2011	5,392,820	$	1.85	$	28,354,726	4.4
Exercisable at June 30, 2011	5,218,943	$	1.80	$	27,693,593	4.4

(1) Based upon the difference between the market price of our common stock on the last trading date of the period ($7.10 as of June 30, 2011) and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

There were 86,875 Stock Options exercised during the year ended June 30, 2011 with an aggregate intrinsic value of $493,923. There were 3,000 Stock Options exercised during the year ended June 30, 2010 with an aggregate intrinsic value of $13,620. There were no Stock Options or Incentive Warrants that were exercised during the year ended June 30, 2009.

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Note 7 Stock-Based Incentive Plan (Continued)

A summary of the status of our unvested Stock Options and Incentive Warrants as of June 30, 2011 and the changes during the year ended June 30, 2011, is presented below:

	Number of Stock Options and Incentive Warrants	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2010	552,582	$ 2.04
Granted		
Vested	(375,580)	$ 1.97
Forfeited	(3,125)	$ 1.83
Unvested at June 30, 2011	173,877	$ 2.20

During the years ended June 30, 2011, June 30, 2010 and 2009, there were 375,580, 539,330 and 1,063,029 Stock Options and Incentive Warrants that vested with a total grant date fair value of $739,893, $1,024,727 and $1,870,931, respectively.

The total unrecognized compensation cost at June 30, 2011, relating to non-vested Stock Options and Incentive Warrants was $354,050. Such unrecognized expense is expected to be recognized over a weighted average remaining service period of 0.75 years.

Restricted Stock

Stock-based compensation expense related to Restricted Stock grants for the years ended June 30, 2011, 2010 and 2009 was $820,980, $576,307 and $249,405, respectively. See Note 6 for a detail of Restricted Stock transactions during the years ended June 30, 2011, 2010 and 2009.

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2011:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2010	403,159	$ 3.15
Granted	303,603	$ 5.52
Vested	(206,858)	$ 3.84
Forfeited	(4,215)	$ 3.11
Unvested at June 30, 2011	495,689	$ 4.30

During the years ended June 30, 2011, June 30, 2010 and 2009, there were 206,858, 243,954 and 50,898 Restricted Stock that vested with a total grant date fair value of $794,335, $551,336 and $209,191, respectively.

At June 30, 2011, unrecognized stock compensation expense related to Restricted Stock grants totaled $1,987,569. Such unrecognized expense will be recognized over a weighted average remaining service period of 2.7 years.

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Note 8 Supplemental Disclosure of Cash Flow Information

Our supplemental disclosures of cash flow information for the year ended June 30, 2011, 2010 and 2009 are as follows:

		Year Ended June 30,	
	2011	2010	2009
Income taxes paid:	$ 229,802	$ 329,800	$ 15,000
Income tax refunds and net operating loss carry-back received:	$ 979,177	$ 2,095,126	4,057,772
Non-cash transactions:			
Decrease in accounts payable used to acquire oil and natural gas leasehold interests and develop oil and natural gas properties:	$ (91,483)	$ (62,532)	$ (2,043,235)
Oil and natural gas properties incurred through recognition of asset retirement obligations:	$ 15,000	$ 85,871	$ 502,814
Windfall tax benefit recognized in income taxes recoverable:	$	$ 173,157	

Note 9 Income Taxes

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

There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits during the year ended June 30, 2011, 2010 and 2009. We believe that we have appropriate support for the income tax positions taken and to be taken on the Company s tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company s tax returns are open to audit under the statute of limitations for the years ending June 30, 2008 through June 30, 2010 for federal tax purposes and for the years ended June 30, 2007 through June 30, 2010 for state tax purposes.

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

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

	June 30, 2011	June 30, 2010	June 30, 2009
Current:			
Federal	$ (64,068)	$ (608,339)	$ (1,993,988)
State	132,596	207,952	157,736
Total current income tax provision (benefit)	68,528	(400,387)	(1,836,252)
Deferred:			
Federal	360,174	(553,326)	528,787
State	20,212	(218,111)	290,601
Total deferred income tax provision (benefit)	380,386	(771,437)	819,388
Total income tax provision (benefit)	$ 448,914	$ (1,171,824)	$ (1,016,864)

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 9 Income Taxes (Continued)

The following is a reconciliation of statutory income tax expense to our income tax provision (benefit):

	June 30, 2011	June 30, 2010	June 30, 2009
Income tax provision (benefit) computed at the statutory federal rate:	$ 70,503	$ (1,210,241)	$ (1,230,275)
Reconciling items:			
State income taxes, net of federal tax benefit	100,853	(10,413)	148,134
Stock-based compensation (primarily incentive stock options)	140,620	105,402	264,060
Deferred tax asset valuation adjustment			(152,588)
Reversal of Section 199 deductions as a result of carry-backs	141,920		
Rate adjustment	(7,172)	(42,651)	21,931
Other	2,190	(13,921)	(68,126)
Income tax provision (benefit)	$ 448,914	$ (1,171,824)	$ (1,016,864)

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below:

	June 30, 2011	June 30, 2010	June 30, 2009
Deferred tax assets:			
Non qualified stock-based compensation	$ 959,547	$ 866,035	$ 657,369
Net operating loss carry-forwards**	5,910,275	5,389,065	5,389,065
AMT credit carry-forward*	682,456	645,938	
Other	23,626	21,306	22,841
Gross deferred tax assets	7,575,904	6,922,344	6,069,275
Valuation allowance	(5,187,983)	(5,187,983)	(5,187,983)
Total deferred tax assets	2,387,921	1,734,361	881,292
Deferred tax liability:			
Oil and natural gas properties	(5,718,187)	(4,684,241)	(4,602,609)
Total deferred tax liability	(5,718,187)	(4,684,241)	(4,602,609)
Net deferred tax liability	$ (3,330,266)	$ (2,949,880)	$ (3,721,317)

* Total AMT credit carry-forward is $812,325. Our net deferred tax liability does not include $129,869 of AMT credit carry-forward associated with the windfall tax benefit.

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

We recovered approximately $1.0 million, $2.1 million , and $3.6 million in federal income taxes, as a result of the carry-back of tax losses incurred during June 30, 2010, 2009, and 2008, respectively. The loss carry-backs were primarily the result of significant intangible drilling costs incurred during those years, which we deducted for federal income tax purposes.

At June 30, 2011, we have a federal tax loss carry-forward of approximately $18.5 million. Included in the deferral tax loss carry-forward is approximately $15.9 million that we acquired through the reverse merger in May 2004, of which, approximately $0.6 million is available to us to use in equal amounts through 2023. We have applied a valuation allowance against the portion of the federal tax loss carry-forward that has been disallowed through IRC Section 382.

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Note 10 Related Party Transactions

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

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

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

See also Note 6 for equity transactions with related parties.

Note 11 Net Loss Per Share

The following table sets forth the computation of basic and diluted loss per share:

		Year Ended June 30,	
	2011	**2010**	**2009**
Numerator			
Net loss	$ (241,553)	$ (2,387,707)	$ (2,601,593)
Denominator			
Weighted average number of common shares basic and diluted	27,437,496	27,004,066	26,461,057
Net Loss per common share basic and diluted	$ (0.01)	$ (0.09)	$ (0.10)

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

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

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

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

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 11 Net Loss Per Share (Continued)

Outstanding potentially dilutive securities as of June 30, 2009 are as follows:

Outstanding Potential Dilutive Securities		**Weighted Average Exercise Price**	**Outstanding at June 30, 2009**
Common stock warrants issued in connection with equity and financing transactions	$	1.46	348,058
Stock Options and Incentive Warrants	$	1.83	5,485,820
Total	$	1.81	5,833,878

Note 12 Commitments and Contingencies

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

We, and our wholly owned subsidiary NGS Sub Corp., are defendants in a lawsuit filed by John C. McCarthy et. al., in the Fifth District Court, Richland Parish Louisiana, in July 2011 (the McCarthy lawsuit). The plaintiffs in the McCarthy lawsuit allege, among other claims, that the defendants fraudulently and wrongfully purchased the plaintiffs income royalty rights in the Delhi Field Unit in the Holt-Bryant Reservoir in May 2006. The plaintiffs are making a claim for, among other things, a rescission of the purchase by us of the income royalty rights, consequential damages and other relief. The claim is still in the early stages of discovery. We believe we complied with our obligations with the former royalty owners in connection with the purchase, and we intend to vigorously defend our position. We do not believe that the ultimate resolution of this litigation will have a material adverse effect on our financial position or results of operation.

We are defendants in a lawsuit filed by Frederick M. Garcia and Lydia Garcia in the 229th District Court, Duval County Texas, in December 2010 (the Garcia lawsuit). The plaintiffs in the Garcia lawsuit allege, among other claims, that defendant failed to maintain its oil and gas mineral lease beyond its primary term, allegedly due to no production (or insufficient production) of any minerals occurring on or prior to the expiration of the primary term. The plaintiffs are making a claim, among other things, for a declaratory judgment declaring expiration of the lease agreement, defendant s vacating the premises, and plaintiffs right to enter into a new lease with any other person of their choosing, in addition to legal damages for plaintiffs financial harm. The claim is still in the early stages of discovery. We believe we complied with our obligations to maintain the mineral lease beyond its primary term, via the establishment and maintenance of sufficient production under the terms of the lease agreement and Texas State law, and we intend to vigorously defend our position. We do not believe that the ultimate resolution of this litigation will have a material adverse effect on our financial position or results of operation.

In the aggregate, based on our petroleum reserves at June 30, 2011, our range of loss is estimated to be zero to not more than 145,000 barrels of proved oil reserves (or 1.1% of our 13.85 million BOE proved reserves), not more than $100,000 in consequential damages, net of purchase price adjustments, and an un-determinable amount of damages for legal harm, interest, legal fees and expenses.

Lease Commitments. We have a non-cancelable operating lease for office space that expires on August 1, 2016. Future minimum lease commitments as of June 30, 2011 under this operating lease are as follows:

For the year ended June 30,		
2012		157,268
2013		159,011
2014		159,011
2015		159,011
2016		159,011
Thereafter		13,251
Total	$	806,563

Rent expense for the year ended June 30, 2011, 2010 and 2009 was $146,263, $138,823 and $149,397, respectively.

Employment Contracts. We have entered into employment agreements with the Company s three senior executives. The employment contracts provide for a severance package for termination by the Company for any reason other than cause or permanent disability, or in the event of a constructive termination, that includes payment of base pay and certain medical and disability benefits from six months to a year after termination. The total contingent obligation under the employment contracts as of June 30, 2011 is approximately $523,562.

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Note 13 Concentrations of Credit Risk

Major Customers. We market all of our oil and natural gas production from the properties we operate. The majority of our operated gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-based prices. The following table identifies customers from whom we derived 10 percent or more our net oil and natural gas revenues during the years ended June 30, 2011, 2010 and 2009. Based on the current demand for oil and natural gas and availability of other customers, we do not believe the loss of any of these customers would have a significant affect on our operations or financial condition.

	Percent of Total Revenue		
Customer	**Year Ended June 30, 2011**	**Year Ended June 30, 2010**	**Year Ended June 30, 2009**
Enterprise Crude Oil LLC	15%	31%	
Copano Field Services/Upper Gulf Coast, L.P.	7%	23%	2%
Plains Marketing L.P.	60%	12%	40%
ETC Texas Pipeline, LTD.	12%	19%	36%
DCP Midstream, LP	6%	15%	16%

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

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

Note 14 Retirement Plan

Effective February 1, 2007, we implemented a 401(k) Savings Plan which covers all full-time employees. At our discretion, we may match a certain percentage of the employees contributions to the plan. The matching percentage is currently 100% of the first 4% of each participant s compensation, vesting fully upon our contributions. Our matching contribution to the plan was $77,168, $87,846 and $58,884 for the years ended June 30, 2011, 2010 and 2009, respectively.

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Note 15 Subsequent Events

Series A Cumulative Preferred Stock

On July 1, 2011, we sold 220,000 shares of our 8.5% Series A Cumulative Preferred Stock, par value $0.001 per share and liquidation preference $25.00 per share (the Series A Preferred Stock) for net proceeds of $4.5 million. The Series A Preferred Stock cannot be converted into common stock of the Company, but may be redeemed by the Company, at the Company s option, on or after July 1, 2014 for $25.00 per share. In the event of a change of control of the Company, the Series A Preferred Stock may be redeemable by the Company, at the Company s option, at $25.75 per share on or before July 1, 2012, $25.50 after July 1, 2012, $25.25 after July 1, 2013, and $25.00 on or after July 2, 2014. We will pay cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.50% per annum of the $25.00 per share liquidation preference.

Additionally, during the period from July 19, 2011 through September 7, 2011, we issued 31,150 shares of Series A Preferred Stock in open market transactions at an average price of $25.54 per share pursuant to an At the Market sales agreement (ATM) we have with our sales agent for total net proceeds of approximately $771,783, after commissions. Sales of shares of our Series A Preferred Stock by our sales agent have been made in privately negotiated transactions or in any method permitted by law deemed to be an At The Market offering as defined in Rule 415 promulgated under the Securities Act of 1933, as amended, at negotiated prices, at prices prevailing at the time of sale or at prices related to such prevailing market prices, including sales made directly on the NYSE Amex or sales made through a market maker other than on an exchange. Our sales agent as made all sales using commercially reasonable efforts consistent with its normal sales and trading practices on mutually agreed upon terms between our sales agent and us.

We paid dividends on our Series A Preferred Stock of $38,958 and $44,011 to holders of record, on July 28, 2011 and August 30, 2011, respectively.

Note 16 Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited)

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

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Development costs also include amounts incurred due to the recognition of asset retirement obligations, of $15,000, $85,871 and $502,814, during the years ended June 30, 2011, 2010 and 2009, respectively.

	For the Years Ended June 30		
	2011	2010	2009
Oil and Natural Gas Activities	$	$	$
Property acquisition costs:			
Proved property	465,176	391,785	876,640
Unproved property	523,591	185,154	1,413,941
Exploration costs	215,660	2,354,239	349,403
Development costs	2,200,905	890,116	6,486,158
Total costs incurred for oil and natural gas activities	$ 3,405,332	$ 3,821,294	$ 9,126,142

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of the net proved oil and natural gas reserves of our oil and gas properties located entirely within the United States of America are based on evaluations prepared by third-party reservoir engineers. Reserve volumes and values were determined under the method prescribed by the SEC for our fiscal year ended June 30, 2011 and 2010, which requires the application of the previous 12-month unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected reserve life, when estimating whether reserve quantities are economical to produce. The 2009 data is presented in accordance with oil and gas disclosure requirements effective during that period.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 16 Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (Continued)

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

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

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
July 1, 2008	952,041	1,310,460	10,534,391	4,018,233
Revisions of previous estimates	(92,729)	(272,689)	(4,498,026)	(1,115,089)
Purchases of minerals in place	122,662	60,648	645,724	290,931
Production (sales volumes)	(36,026)	(44,125)	(323,301)	(134,035)
June 30, 2009	945,948	1,054,294	6,358,788	3,060,040
Revisions of previous estimates	(113,487)	(19,147)	430,145	(60,943)
Improved recovery, extensions and discoveries	9,451,758	29,300	381,695	9,544,674
Production (sales volumes)	(29,749)	(27,820)	(407,674)	(125,515)
June 30, 2010	10,254,470	1,036,627	6,762,954	12,418,256
Revisions of previous estimates	1,475,918	(84,154)	3,273,846	1,937,405
Improved recovery, extensions and discoveries			779,556	129,926
Sales of minerals in place	(104,577)	(221,469)	(1,173,850)	(521,688)
Production (sales volumes)	(57,965)	(18,704)	(238,607)	(116,437)
June 30, 2011	11,567,846	712,300	9,403,899	13,847,462
Proved developed reserves:				
June 30, 2008	96,167	109,716	561,001	299,383
June 30, 2009	104,731	141,372	1,106,028	430,441
June 30, 2010	706,053	157,302	1,536,858	1,119,498
June 30, 2011	4,986,337	100,900	1,543,401	5,344,471

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

Total proved reserves increased 9.4 million BOE from 3,060,040 BOE at June 30, 2009 to 12,418,256 BOE at June 30, 2010. The increase is primarily attributable to improved recovery of 9,411,841 barrels of proved oil reserves added to our properties in the Delhi Field, based on approximately $300 million of development capital spent by the Operator since project inception, the start-up of CO2 injection operations during fiscal year 2010, and oil production response during fiscal year 2010. The additions to our properties in the Delhi Field along with extensions in Giddings and Oklahoma of 127,905 BOE, were offset by production of 125,515 BOE and negative revisions of 60,943 BOE primarily related to the transfer of four well locations in the Lopez Field in South Texas from the proved classification to probable during 2010.

The revisions of previous estimates during our fiscal year ended June 30, 2009, were due primarily to the decline in the price of natural gas. During the year ended June 30, 2008, the revisions of previous estimates were primarily due to the identification and separation of natural gas liquids in 2008 and the effects of the new SEC guideline on PUD locations with fractured reservoirs. Natural gas liquids were not separately identified in the June 30, 2007 independent report prepared by Von Gonten. Purchases of minerals in place during 2009 resulted from leasehold acquisitions of proved undeveloped reserves in the Giddings Field and in our Neptune Oil Project in South Texas.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 16 Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (Continued)

Standardized Measure of Discounted Future Net Cash Flows

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

The standardized measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2011, 2010 and 2009 are as follows:

	For the Years Ended June 30		
	2011	**2010**	**2009**
Future cash inflows	$ 1,161,278,060	$ 827,902,260	$ 127,639,699
Future production costs and severance taxes	(379,493,392)	(222,826,052)	(36,128,247)
Future development costs	(40,571,895)	(34,024,112)	(33,317,000)
Future income tax expenses	(278,455,798)	(213,063,769)	(15,697,532)
Future net cash flows	462,756,975	357,988,327	42,496,920
10% annual discount for estimated timing of cash flows	(234,309,020)	(196,361,678)	(18,947,129)
Standardized measure of discounted future net cash flows	$ 228,447,954	$ 161,626,649	$ 23,549,791

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12-month unweighted arithmetic average first-day-of-the-month commodity prices for the year ended June 30, 2011 and 2010 and period-end commodity prices for the year ended June 30, 2009. The commodity prices are adjusted by lease for quality, transportation fees, energy content and regional price differentials.

	Year Ended June 30,	
2011	**2010**	**2009**

	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
Commodity prices used in determining future cash flows	$ 90.09	$ 4.21	$ 75.76	$ 4.10	$ 69.89	$ 3.89

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

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 16 Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (Continued)

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

	For the Years Ended June 30 2011	2010	2009
Balance, beginning of year	$ 161,626,649	$ 23,549,791	$ 97,072,641
Net changes in sales prices and production costs related to future production	57,178,860	3,935,863	(144,680,473)
Changes in estimated future development costs	(16,028,728)	(3,502,403)	24,399,826
Sales of oil and gas produced during the period, net of production costs	(6,151,549)	(3,356,822)	(4,654,400)
Net change due to purchases of minerals in place			2,683,261
Net change due to extensions, discoveries, and improved recovery	623,446	236,828,138	
Net change due to revisions in quantity estimates	56,766,220	(934,602)	(20,564,731)
Net change due to sales of minerals in place	(8,233,734)		
Development costs incurred during the period	2,416,565		5,960,423
Accretion of discount	26,597,834	3,582,622	13,315,725
Net change in discounted income taxes	(42,490,270)	(91,991,767)	50,903,834
Other	(3,857,339)	(6,484,171)	(886,315)
Balance, end of year	$ 228,447,954	$ 161,626,649	$ 23,549,791

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

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

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

Management s Report on Internal Control Over Financial Reporting

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

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

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company s internal control over financial reporting based on criteria established in the Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2011.

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Changes in Internal Control Over Financial Reporting

There has been no change in the Company s internal control over financial reporting during the fourth quarter ended June 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers And Corporate Governance

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2011 fiscal year.

Item 11. Executive Compensation

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2011 fiscal year.

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

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2011 fiscal year.

Item 13. Certain Relationships and Related Transactions, Director Independence

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2011 fiscal year.

Item 14. Principal Accountant Fees and Services

Incorporated by reference to the Company s Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company s 2011 fiscal year.

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PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. Financial Statements.

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

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Cash Flows

Consolidated Statements of Stockholders Equity

Notes to the Consolidated Financial Statements

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

None.

3. Exhibits

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

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SIGNATURES

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

Evolution Petroleum Corporation

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

Date: September 13, 2011

EBITDA

September 30

$

%

(Dollars in millions)

Powder River Basin Mining
$
197.5

$
91.7

$
289.2

$
278.3

$
10.9

4
 %
Midwestern U.S. Mining
96.0

50.0

146.0

172.4

(26.4
)

(15
)%
Western U.S. Mining
79.4

50.0

129.4

83.2

46.2

56
 %
Australian Metallurgical Mining
215.0

109.6

324.6

(121.0
)

445.6

368
%
Australian Thermal Mining
203.7

75.6

279.3

137.2

142.1

104
%
Trading and Brokerage
(2.4
)

8.8

6.4

(41.3
)

47.7

115
%
Corporate and Other
(60.1
)

(44.4
)

(104.5
)

(270.8
)

166.3

61
%
Adjusted EBITDA
$
729.1

$
341.3

$
1,070.4

$
238.0

$
832.4

350
%
Powder River Basin Mining. Segment Adjusted EBITDA decreased during the three months ended September 30, 2017 compared to the same period in the prior year due to lower realized coal pricing, net of sales-related costs ($9.7 million), higher materials, services and repairs costs ($3.7 million) and increased pricing for fuel and explosives ($2.9 million), partially offset by reduced lease expenses resulting from early lease buyouts ($6.0 million). Segment

Adjusted EBITDA increased during the nine months ended September 30, 2017 compared to the same period in the prior year due to higher volume driven by increased natural gas pricing ($50.6 million) and reduced expenses for leases ($16.5 million) and labor ($12.3 million), partially offset by lower realized coal pricing, net of sales-related costs ($59.0 million) and increased pricing for fuel and explosives ($11.4 million).

Midwestern U.S. Mining. Segment Adjusted EBITDA decreased during the three and nine months ended September 30, 2017 compared to the same periods in the prior year primarily due to higher materials, services and repairs costs (three months, $4.4 million; nine months, $13.3 million), increased pricing for fuel and explosives (three months, $1.5 million; nine months, $8.2 million) and lower realized coal pricing, net of sales-related costs (three months, $2.7 million; nine months, $7.4 million).

Western U.S. Mining. Segment Adjusted EBITDA increased during the nine months ended September 30, 2017 compared to the same period in the prior year primarily due to improved sales volumes from higher margin operations ($27.3 million), the liquidated damages settlement collected from Arizona Public Service Company and PacifiCorp ($13.0 million) and decreased spending for materials, services and repairs costs ($12.7 million), partially offset by lower realized coal pricing, net of sales-related costs ($5.5 million).

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Australian Metallurgical Mining. Segment Adjusted EBITDA increased during the three and nine months ended September 30, 2017 compared to the same periods in the prior year primarily driven by improved realized coal pricing, net of sales-related costs (three months, $155.2 million; nine months, $478.2 million), improved volumes at our North Goonyella Mine (three months, $23.5 million; nine months, $14.9 million) resulting from longwall moves in the prior year, improved production volumes at our Coppabella Mine (three months, $14.8 million; nine months, $19.2 million) and lower contractor and rail costs due to the cessation of mining activities at our Burton Mine during the fourth quarter of 2016 (nine months, $14.8 million). The increases were offset by the impact of Cyclone Debbie, unfavorable foreign exchange rate movements (three months, $9.4 million; nine months, $16.1 million) and cost escalations (three months, $6.0 million; nine months, $17.5 million).

Australian Thermal Mining. Segment Adjusted EBITDA increased during the three and nine months ended September 30, 2017 compared to the same periods in the prior year primarily due to improved realized coal pricing, net of sales-related costs (three months, $69.9 million; nine months, $197.5 million) and improved production and leasing costs at our Wilpinjong Mine (three months, $6.8 million), offset by lower sales volume caused by geological issues at our Wambo Mine (three months, $26.8 million; nine months, $28.2 million) and higher fuel pricing and other cost escalations (three months, $3.5 million; nine months, $13.3 million).

Trading and Brokerage. Segment Adjusted EBITDA increased during the three and nine months ended September 30, 2017 compared to the same periods in the prior year primarily due to market and business opportunities recognized.

Corporate and Other Adjusted EBITDA. The following tables present a summary of the components of Corporate and Other Adjusted EBITDA:

Three Month Comparison	2017	2016		
	Successor	Predecessor	(Decrease) Increase	
	Three Months Ended September 30		to Income	
	(Dollars in millions)		Tons	$
Resource management activities [1]	$0.4	$ 1.3	$(0.9)	(69)%
Selling and administrative expenses (excluding debt restructuring)	(33.4)	(32.1)	(1.3)	(4)%
Restructuring charges	(1.1)	(0.3)	(0.8)	(267)%
Corporate hedging	7.3	(47.4)	54.7	115 %
Other items, net [2]	(2.2)	(13.6)	11.4	84 %
Corporate and Other Adjusted EBITDA	$(29.0)	$ (92.1)	$63.1	69 %

(1) Includes gains (losses) on certain surplus coal reserve and surface land sales and property management costs and revenues.

(2) Includes results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and amortization of basis difference), costs associated with post-mining activities, certain coal royalty expenses, gains (losses) on certain asset disposals, minimum charges on certain transportation-related contracts and expenses related to our other commercial activities.

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Nine Month Comparison	2017			2016		
	Successor	Predecessor	Combined	Predecessor	(Decrease) Increase to Income	
	April 2 through September 30	January 1 through April 1	Nine Months Ended September 30		$	%
	(Dollars in millions)					
Resource management activities [1]	$1.6	$ 2.9	$4.5	$ 11.3	$(6.8)	(60)%
Selling and administrative expenses (excluding debt restructuring)	(67.8)	(37.2)	(105.0)	(93.1)	(11.9)	(13)%
Restructuring charges	(1.1)	—	(1.1)	(15.5)	14.4	93 %
Corporate hedging	6.9	(27.6)	(20.7)	(197.8)	177.1	90 %
UMWA voluntary employee beneficiary association settlement	—	—	—	68.1	(68.1)	(100)%
Gain on sale of interest in Dominion Terminal Associates	—	19.7	19.7	—	19.7	n.m.
Other items, net [2]	0.3	(2.2)	(1.9)	(43.8)	41.9	96 %
Corporate and Other Adjusted EBITDA	$(60.1)	$ (44.4)	$(104.5)	$ (270.8)	$166.3	61 %

(1) Includes gains (losses) on certain surplus coal reserve and surface land sales and property management costs and revenues.

(2) Includes results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and amortization of basis difference), costs associated with past mining activities, certain coal royalty expenses, gains (losses) on certain asset disposals, minimum charges on certain transportation-related contracts and expenses related to our other commercial activities.

The increases associated with corporate hedging results, which includes foreign currency and commodity hedging, were due to a decrease in realized losses as compared to the same period in the prior year. The increases associated with “Other items, net” were primarily attributable to improved Middlemount results as compared to the prior year driven by higher pricing. During the first quarter of 2017, a $19.7 million gain was recorded in connection with the sale of our interest in Dominion Terminal Associates. Restructuring charges for the nine months ended September 30, 2017 decreased as workforce reductions were made during 2016 at multiple mines in our Power River Basin Mining and Midwestern U.S. Mining segments. During 2016, a gain of $68.1 million was recognized for the voluntary employee beneficiary association (VEBA) settlement with the United Mine Workers of America (UMWA) as further described in Note 5. “Discontinued Operations” of the accompanying unaudited condensed consolidated financial statements. The increases in selling and administrative expenses were driven by charges for shared-based compensation expense.

Depreciation, Depletion and Amortization. The following table presents a summary of depreciation, depletion and amortization expense by segment:

	2017	2016	2017		2016
	Successor	Predecessor	Successor	Predecessor	Predecessor
	Three Months Ended September 30		April 2 through September 30	January 1 through April 1	Nine Months Ended September 30
	(Dollars in millions)				
Powder River Basin Mining	$(57.4)	$ (33.5)	$(95.6)	$ (32.0)	$ (90.2)

Midwestern U.S. Mining	(38.1)	(12.9)	(73.4)	(13.3)	(40.1)
Western U.S. Mining	(32.9)	(11.2)	(57.7)	(23.6)	(34.3)
Australian Metallurgical Mining	(37.1)	(30.9)	(64.3)	(20.6)	(90.3)
Australian Thermal Mining	(25.7)	(26.2)	(45.5)	(24.0)	(77.2)
Trading and Brokerage	(0.1)	—	(0.1)	—	(0.1)
Corporate and Other	(3.2)	(3.1)	(6.2)	(6.4)	(13.3)
Total	$(194.5)	$ (117.8)	$(342.8)	$ (119.9)	$ (345.5)

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Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments:

	2017 Successor	2016 Predecessor	2017 Successor	2016 Predecessor	2016 Predecessor
	Three Months Ended September 30		April 2 through September 30	January 1 through April 1	Nine Months Ended September 30
Powder River Basin Mining	$0.84	$ 0.69	$0.83	$ 0.69	$ 0.73
Midwestern U.S. Mining	0.83	0.54	0.78	0.61	0.52
Western U.S. Mining	1.06	0.91	1.06	4.30	0.91
Australian Metallurgical Mining	0.66	4.29	0.68	4.72	4.24
Australian Thermal Mining	1.73	2.59	1.72	2.62	2.61

Depreciation, depletion and amortization expense for the Successor three months ended September 30, 2017 includes depletion expense ($50.3 million), amortization of the fair value of certain U.S. coal supply agreements ($41.5 million), amortization associated with our asset retirement obligation assets ($14.8 million) and depreciation expense ($87.9 million). Depreciation, depletion and amortization expense was higher for the Successor three months ended September 30, 2017 as compared to the Successor period April 2 through June 30, 2017 as the result of volume increases in the period which impacted the portion of our depreciation, depletion and amortization expense that is recorded on a units-of-production method.

Depreciation, depletion and amortization expense for the Predecessor period January 1 through April 1, 2017 reflected additional expense at some of our mines due to changes in the estimated life of mine and at Corporate and Other for leasehold improvements that were vacated in 2017. The additional expense was offset by a decrease at our Metropolitan Mine as the assets were classified as held for sale during the period and depreciation, depletion and amortization was therefore not recorded. The share sale and purchase agreement related to our Metropolitan Mine was terminated in April 2017, as discussed in Note. 16. “Other Events” to the accompanying unaudited condensed consolidated financial statements. Depreciation, depletion and amortization expense for the three and nine months ended September 30, 2016 was impacted by a reduction in the asset bases at several of our mines due to impairment charges that had been recognized during 2015.

Selling and Administrative Expenses Related to Debt Restructuring. The general and administrative expenses related to debt restructuring recorded during 2016 related to legal and other expenditures made in connection with debt restructuring initiatives prior to the Debtors’ filing of the Bankruptcy Petitions.

Asset Impairment. Refer to Note 4. “Asset Impairment” in the accompanying unaudited condensed consolidated financial statements for information surrounding the impairment charges recorded during the Predecessor period January 1 through April 1, 2017 and the nine months ended September 30, 2016.

Interest Expense. Interest expense for the Successor Company primarily related to the 6.000% Senior Secured Notes due March 2022, the 6.375% Senior Secured Notes due March 2025 and the Senior Secured Term Loan due 2022. For additional details on debt, refer to Note 3. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” and Note. 13. “Long-term Debt” to the accompanying unaudited condensed consolidated financial statements.

Interest expense for the Predecessor period January 1 through April 1, 2017 and the three and nine months ended September 30, 2016, was impacted by our filing of the Bankruptcy Petitions, which resulted in only accruing adequate protection payments subsequent to the Petition Date to certain secured lenders and other parties in accordance with Section 502(b)(2) of the Bankruptcy Code.

Loss on Early Debt Extinguishment. The loss on early debt extinguishment recorded on the Successor Company, related to the amendment of the Senior Secured Term Loan due 2022 as described in Note 13. “Long-term Debt” to the accompanying unaudited condensed consolidated financial statements.

Break Fees Related to Terminated Asset Sales. The Successor Company received break fees of $28.0 million during the period April 2 through September 30, 2017 related to terminated asset sales which are further described in Note 16. “Other Events” of the accompanying unaudited condensed consolidated financial statements.
Unrealized (Losses) Gains on Economic Hedges. Unrealized (losses) gains primarily relate to mark-to-market activity from financial contract trading activities.

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Coal Inventory Revaluation. As a part of the fresh start reporting adjustments, the book value of coal inventories was increased to reflect the estimated fair value, less costs to sell the inventories. During the Successor period April 2 through September 30, 2017, this adjustment was fully amortized as the inventory was sold. For additional details, refer to Note 3. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” to the accompanying unaudited condensed consolidated financial statements.

Take-or-Pay Contract-Based Intangible Recognition. Included in the fresh start reporting adjustments were contract-based intangible liabilities for port and rail take-or-pay contracts. During the Successor three months ended September 30, 2017 and the period April 2 through September 30, 2017, the Company has ratably recognized these contract-based intangible liabilities. For additional details, refer to Note 3. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” to the accompanying unaudited condensed consolidated financial statements.

Reorganization Items, Net. The reorganization items recorded during the Predecessor period January 1 through April 1, 2017 reflected the impact of the Plan provisions and the application of fresh start reporting. Expense recorded during the three and nine months ended September 30, 2016 related to expenses recorded in connection with our Chapter 11 Cases. Refer to Note 3. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” to the accompanying unaudited condensed consolidated financial statements for further information regarding our reorganization items.

Income (Loss) from Continuing Operations, Net of Income Taxes

The following tables present income (loss) from continuing operations, net of income taxes:

	2017 Successor	2016 Predecessor	2017 Successor	Predecessor	2016 Predecessor
	Three Months Ended September 30		April 2 through September 30	January 1 through April 1	Nine Months Ended September 30
	(Dollars in millions)				
Income (loss) from continuing operations before income taxes	$149.6	$ (108.5)	$255.7	$ (459.3)	$ (596.8)
Income tax benefit	(84.1)	(10.8)	(79.4)	(263.8)	(108.2)
Income (loss) from continuing operations, net of income taxes	$233.7	$ (97.7)	$335.1	$ (195.5)	$ (488.6)

Income Tax Benefit. The income tax benefit recorded for the Successor periods presented primarily related to expected refunds for U.S. net operating loss carrybacks.

The income tax benefit recorded for the Predecessor period January 1 through April 1, 2017, was primarily comprised of benefits related to Predecessor deferred tax liabilities ($177.8 million), accumulated other comprehensive income ($81.5 million) and unrecognized tax benefits ($6.7 million). Refer to Note 12. “Income Taxes” in the accompanying unaudited condensed consolidated financial statements for additional information.

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Net Income (Loss) Attributable to Common Stockholders

The following tables present net loss attributable to common stockholders:

	2017 Successor	2016 Predecessor	2017 Successor	Predecessor	2016 Predecessor
	Three Months Ended September 30		April 2 through September 30	January 1 through April 1	Nine Months Ended September 30
	(Dollars in millions)				
Income (loss) from continuing operations, net of income taxes	$233.7	$ (97.7)	$335.1	$ (195.5)	$ (488.6)
Loss from discontinued operations, net of income taxes	(3.7)	(38.1)	(6.4)	(16.2)	(44.5)
Net income (loss)	230.0	(135.8)	328.7	(211.7)	(533.1)
Less: Series A Convertible Preferred Stock dividends	23.5	—	138.6	—	—
Less: Net income attributable to noncontrolling interests	5.1	1.8	8.9	4.8	3.5
Net income (loss) attributable to common stockholders	$201.4	$ (137.6)	$181.2	$ (216.5)	$ (536.6)

Loss from Discontinued Operations, Net of Income Taxes. The loss from discontinued operations for the Predecessor three and nine months ended September 30, 2016 was primarily comprised of a charge of $35.0 million for the UMWA 1974 Pension Plan. For additional details, refer to Note 5. “Discontinued Operations” to the accompanying unaudited condensed consolidated financial statements.

Series A Convertible Preferred Stock Dividends. The Series A Convertible Preferred Stock dividends for the Successor three months ended September 30, 2017 and the period April 2 through September 30, 2017 were comprised of the deemed dividends (three months, $23.5 million; nine months, $135.5 million) granted for the Preferred Stock shares that were converted during the respective periods and the first semi-annual payment of preferred dividends (nine months, $3.1 million) which was pro-rated for the period of April 3 through April 30, 2017.

Diluted EPS

The following table presents diluted EPS:

	2017 Successor	2016 Predecessor	2017 Successor	Predecessor	2016 Predecessor
	Three Months Ended September 30		April 2 through September 30	January 1 through April 1	Nine Months Ended September 30
Diluted EPS attributable to common stockholders:					
Income (loss) from continuing operations	$1.49	$ (5.44)	$1.37	$ (10.93)	$ (26.91)
Loss from discontinued operations	(0.02)	(2.09)	(0.05)	(0.88)	(2.43)
Net income (loss)	$1.47	$ (7.53)	$1.32	$ (11.81)	$ (29.34)

Diluted EPS is commensurate with the changes in results from continuing operations and discontinued operations during that period. Diluted EPS for the Successor Company reflects weighted average diluted common shares outstanding of 103.1 million for the three months ended September 30, 2017 and 100.2 million for the period April 2 through September 30, 2017. Diluted EPS for the Predecessor periods January 1 through April 1, 2017 and the three and nine months ended September 30, 2016 reflect weighted average diluted common shares outstanding of 18.3 million, respectively.

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Outlook

As part of its normal planning and forecasting process, Peabody utilizes a bottom-up approach to develop macroeconomic assumptions for key variables, including country level gross domestic product, industrial production, fixed asset investment and third-party inputs, driving detailed supply and demand projections. This includes demand for coal, electricity generation and steel, while cost curves concentrate on major supply regions/countries that impact the regions in which the Company operates. Our estimates involve risks and uncertainties and are subject to change based on various factors as described more fully in the "Cautionary Notice Regarding Forward-Looking Statements" section contained within this Item 2.

Our near-term outlook is intended to coincide with the next 12 to 24 months, with subsequent periods addressed in our long-term outlook.

Near-Term Outlook

U.S. Thermal Coal. U.S. domestic electricity generation decreased 2% in the nine months ended September 30, 2017 compared to the prior year as a result of mild weather. Even as overall electricity demand weakened year-over-year through September, utility consumption of Powder River Basin coal rose approximately 8% with natural gas consumption decreasing 12% compared to the prior year period (on 30% higher average natural gas prices year-over-year through September).

Cooling degree days in June, July and August 2017 were down approximately 16% from the prior year in coal-heavy regions. As a result, Peabody now expects U.S. coal consumption from electricity generation to be largely flat for full-year 2017 compared to 2016 levels.

Seaborne Thermal Coal. Seaborne thermal coal demand and pricing continue to be supported by robust Asian demand primarily in China and South Korea. Chinese thermal coal imports are up approximately 15 million tonnes year-to-date through September compared to the prior year period on strong electricity generation that exceeded domestic production growth. In addition, South Korean imports have strengthened approximately 15 million tonnes through September, a 23% increase year-over-year, as nuclear generation has been curtailed. While import demand from India has been sluggish on increased domestic coal usage, stockpiles are currently at multi-year lows, which is supportive of additional imports in the fourth quarter. For full-year 2017, Peabody now projects seaborne thermal coal demand to increase approximately 10 to 15 million tonnes from 2016 levels.

Seaborne Metallurgical Coal. With respect to seaborne metallurgical coal, global steel production has risen approximately 5% during the nine months ended September 30, 2017 as compared to the prior year period, led by record Chinese steel production. In addition, Chinese steel exports are down 30% year-to-date through September. Through the nine months ended September 30, 2017 metallurgical coal imports in China rose 9 million tonnes as compared to the prior year period on strong demand and curtailed domestic production on geologic issues. For full-year 2017, Peabody now expects global seaborne metallurgical coal demand to increase approximately 10 million tonnes from 2016 levels.

Seaborne metallurgical coal prompt prices averaged $189 per tonne in the third quarter of 2017, up over $50 per tonne from the prior year, with the index-based settlement price for hard coking coal set at approximately $170 per tonne. In addition, Peabody set third quarter low-vol PCI pricing at $115 per tonne with an additional settlement later in the quarter of $127.50 per tonne. The Company also negotiated a fourth quarter low-vol PCI settlement of $127.50 per tonne.

Long-Term Outlook

There were no significant changes to our Long-term Outlook subsequent to December 31, 2016. Information regarding our Long-term Outlook is outlined in Part II. Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2016, as amended on July 10, 2017 and August 14, 2017.

Regulatory Update

Other than as described in the following section, there were no significant changes to our regulatory matters subsequent to December 31, 2016. Information regarding our regulatory matters is outlined in Part I, Item 1. "Business" in our Annual Report on Form 10-K for the year ended December 31, 2016, as amended on July 10, 2017 and August 14, 2017.

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Regulatory Matters - U.S.

Grid Resiliency Pricing Rule. On October 10, 2017, the Secretary of Energy (the Secretary) published a Notice of Proposed Rulemaking entitled the Grid Resiliency Pricing Rule (the Proposed Rule). The Proposed Rule was issued by the Secretary pursuant to section 403 of the Department of Energy Organization Act. 42 U.S.C. § 7173. In the Proposed Rule, the Secretary instructed the Federal Energy Regulatory Commission (FERC) to impose rules to ensure that reliability and resiliency attributes of certain electric generation units with a 90-day on-site fuel supply are fully compensated for the benefits and services they provide to grid operations. The Secretary directed FERC to take final action on the Proposed Rule within 60 days of publication or, in the alternative, to issue the rule as an interim final rule immediately, with provision for later modifications after consideration of public comments. The Proposed Rule cites the retirements of coal and nuclear plants as a potential threat to grid reliability and resilience, and provides for the creation of a "reliability and resiliency rate" that would compensate certain eligible resources for the benefits and services they provide to grid operations, allowing such eligible resources to recover their fully allocated costs and a fair return on equity. The "reliability and resiliency rate" would be available to eligible resources operating within FERC-approved independent system operators or regional transmission organizations with energy and capacity markets. The rate would apply only to generators that are not currently subject to cost-of-service regulation by a state or other authority.

Clean Air Act (CAA). The CAA, enacted in 1970, and comparable state and tribal laws that regulate air emissions affect our U.S. coal mining operations both directly and indirectly and may result in additional capital and operating costs.

Direct impacts on coal mining and processing operations may occur through the CAA permitting requirements and/or emission control requirements relating to national ambient air quality standards (NAAQS) for particulate matter (PM), sulfur dioxide and ozone. It is possible that modifications to current NAAQS could impact our mining operations in a manner that includes, but is not limited to, designating new nonattainment areas or expanding existing nonattainment areas, requiring changes in vehicle/engine emission standards for vehicles/equipment utilized in our operations, or through the adoption of additional local control measures that could be required pursuant to state implementation plans required to address revised NAAQS.

In recent years the United States Environmental Protection Agency (EPA) has adopted more stringent NAAQS for PM, nitrogen oxide and sulfur dioxide. In 2015, the EPA promulgated a more stringent NAAQS for ozone (80 Fed. Reg. 65,292, (Oct. 25, 2015)). This NAAQS for ozone rule was challenged in the United States Court of Appeals for the D.C. Circuit (D.C. Circuit). Although the rule is not stayed during litigation, on April 7, 2017, the Department of Justice, on behalf of the EPA, filed a motion asking that the case be removed from the argument calendar so that the EPA can consider whether it "should reconsider the rule or some part of it." On April 14, 2017, the D.C. Circuit granted the EPA's motion and stayed the litigation indefinitely with regular 90 day status reports due to the court. More stringent ozone standards require that states develop and submit new state implementation plans to the EPA. Depending on the need for further emission reductions necessary to meet the standard, such plans could include additional control technology requirements for mining equipment or result in additional permitting requirements affecting operations and expansion efforts.

In 2009, the EPA also adopted revised rules to add more stringent PM emissions limits for coal preparation and processing plants constructed or modified after April 28, 2008. The PM NAAQS was thereafter revised and made more stringent (78 Fed. Reg. 3,085 (Jan. 15, 2013). The D.C. Circuit subsequently upheld the revised PM NAAQS (National Association of Manufacturers v. EPA, Nos. 13-1069, 13-1071 (May 9, 2014)). In addition, since 2011, the EPA has required underground coal mines to report on their greenhouse gas emissions. Regulations regarding reporting requirements for underground coal mines were updated in 2016 and now include the ability to cease reporting if mines are abandoned and sealed.

The CAA also indirectly, but significantly affects the U.S. coal industry by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury and other substances emitted by coal-fueled electricity generating plants. Other CAA programs may require further emission reductions and may affect our operations, directly or indirectly.

These include, but are not limited to, the Acid Rain Program, interstate transport rules such as the Cross-State Air Pollution Rule, New Source Performance Standards (NSPS), Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and source permitting programs, including requirements related to New Source Review.

NSPS for Fossil Fuel-Fired Electricity Utility Generating Units (EGUs). On April 13, 2012, pursuant to section 111(b) of the CAA, the EPA published for comment in the Federal Register a proposed NSPS for emissions of carbon dioxide for new, modified and reconstructed fossil fuel-fired EGUs (proposed NSPS). On January 8, 2014, however, the EPA withdrew the proposed NSPS and issued a new proposed NSPS for the same sources. The EPA then issued a Notice of Data Availability (NODA) and technical support document in support of the proposed NSPS on February 26, 2014. After extensions, the public comment period for the re-proposed NSPS and the NODA closed on May 9, 2014. The EPA released the final rule on August 3, 2015, and the rule was published in the Federal Register on October 23, 2015 (80 Fed. Reg. 64,510).

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The final NSPS requires that newly-constructed fossil fuel-fired steam generating units achieve an emission standard for carbon dioxide of 1,400 lb. carbon dioxide per megawatt-hour gross output (CO_2/MWh-gross). The standard is based on the performance of a supercritical pulverized coal boiler implementing partial carbon capture, utilization and storage (CCUS). Modified and reconstructed fossil fuel-fired steam generating units must implement the most efficient generation achievable through a combination of best operating practices and equipment upgrades, to meet an emission standard consistent with best historical performance. Reconstructed units must implement the most efficient generating technology based on the size of the unit (supercritical steam conditions for larger units, to meet a standard of 1,800 lb. CO_2/MWh-gross, and subcritical conditions for smaller units to meet a standard of 2,000 lb. CO_2/MWh-gross).

Sixteen separate petitions for review of the NSPS were filed in the D.C. Circuit, and the challengers included 25 states, utilities, mining companies (including Peabody Energy), labor unions, trade organizations and other groups. The cases were consolidated under a petition filed by North Dakota. States and other organizations intervened in the litigation on behalf of the Respondent EPA.

Four additional cases were filed seeking review of the EPA's denial of reconsideration petitions that were submitted to the EPA regarding the final rule. This denial was published as a final action in the May 6, 2016 Federal Register (81 Fed. Reg. 27,442). States and other organizations also intervened on behalf of the EPA. Upon petitioners' request, the D.C. Circuit suspended the briefing schedule in this case and consolidated the challenges to the EPA's denial of petitions for reconsideration with the previously filed North Dakota case. On August 30, 2016, the Court entered a briefing schedule under which final briefs were due February 6, 2017. Oral arguments were scheduled for April 17, 2017.

On March 28, 2017, however, the EPA moved to hold the case in abeyance pending its reconsideration of the NSPS pursuant to the terms of President Trump's Executive Order on Promoting Energy Independence and Economic Growth (EI Order), which was signed the same day. On April 28, 2017, the court granted the motion to hold the case in abeyance for 60 days and required the EPA to file regular status reports. The court also ordered that parties file supplemental briefs on whether the cases should be remanded to the EPA, rather than held in abeyance. The EPA filed a supplemental brief on May 15, 2017 and, at the present time, the case remains in abeyance and the NSPS remains in effect.

Rules for Regulating Carbon Dioxide Emissions From Existing Fossil Fuel-Fired EGUs. On June 2, 2014, the EPA issued and later formally published for comment proposed rules for regulating carbon dioxide emissions from existing fossil fuel-fired EGUs under section 111(d) of the CAA. On August 3, 2015, the EPA announced the final rule, and published the rule in the Federal Register on October 23, 2015. In the final rule, the EPA established emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel-fired EGUs. These guidelines require that the states individually or collectively create systems that would reduce carbon emissions from steam electric and natural gas-fired power plants located within their borders. Individual states were required to submit their proposed implementation plans to the EPA by September 6, 2016, unless an extension was approved, in which case the states would have until September 6, 2018 to submit those plans. The rule also set emission performance rates for affected sources to be phased in over the period from 2022 through 2030. State plans were required to impose these rates on existing plants or implement other measures (such as emission caps, increased use of renewable energy or energy efficiency measures) that would yield the same result. Overall, the rule was intended to reduce carbon dioxide emissions from steam electric and natural gas-fired power plants by 28% in 2025 and 32% in 2030 compared with 2005 baseline emission rates.

Legal challenges to the rule began when it was still being proposed. One action by an industry petitioner, joined by intervenors, including us, and another by a coalition of states led by West Virginia, asserted that the EPA does not have the authority to issue the regulations of existing power plants under section 111(d) of the CAA. The D.C. Circuit heard oral arguments on the challenges in April 2015. The petitions to enjoin the proposed rulemaking were denied as premature in June 2015. However, the D.C. Circuit acknowledged that a legal challenge could be filed after the EPA issued a final rule. In September 2015 the D.C. Circuit refused to stay the rule, holding that it could not review the rule until it was published in the Federal Register which occurred on October 23, 2015.

Following Federal Register publication of the rule on October 23, 2015, 39 separate petitions for review by approximately 157 entities were filed in the D.C. Circuit challenging the final rule. The petitions reflected challenges by 27 states and governmental entities, as well as challenges by utilities, industry groups, trade associations, coal companies, and other entities. The lawsuits were consolidated with the case filed by West Virginia and Texas (which other States joined). On October 29, 2015, we filed a motion to intervene in the case filed by West Virginia and Texas, in support of the petitioning States. The motion was granted on January 11, 2016. Numerous states and cities were also allowed to intervene in support of the EPA.

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On January 21, 2016, the D.C. Circuit denied the state and industry petitioners' motions to stay the implementation of the rule but provided for an expedited schedule for review of the rule, with oral arguments beginning on June 2, 2016. The state and industry petitioners appealed and filed application for stay with the United States Supreme Court on January 27, 2016. On February 9, 2016, the Supreme Court overruled the lower court and granted the motion to stay implementation of the rule until its legal challenges are resolved. The stay provides that, if a writ of certiorari is sought and the Supreme Court denies the petition, the stay will terminate automatically. The stay also provides that, if the Supreme Court grants the petition for a writ of certiorari, the stay will terminate when the Supreme Court enters its judgment. Briefing on the merits of the petitions for review in the D.C. Circuit has concluded. Oral arguments in the case were heard en banc by ten active D.C. Circuit judges on September 27, 2016 but, to date, the D.C. Court has not yet issued an opinion.

On March 28, 2017, the EPA moved to hold the case in abeyance pending its reconsideration of the final rule pursuant to the EI Order. On April 4, 2017 the EPA published a Federal Register notice announcing that the Agency would review the rule and that it may act to suspend, revise or rescind the rule (82 Fed. Reg. 16,329).

The EI Order included a directive to reexamine the CAA 111(d) rule and, if appropriate, suspend, revise or rescind the rule. On April 28, 2017, the court granted the motion to hold the case in abeyance for 60 days and required the EPA to file regular status reports; the court also ordered that parties file supplemental briefs on whether the cases should be remanded to the EPA, rather than held in abeyance. The EPA filed a supplemental brief on May 15, 2017 and, at the present time, the case remains in abeyance. On October 10, 2017, the EPA reported to the D.C. Circuit Court of Appeals that it signed a Federal Register notice proposing to repeal the Clean Power Plan. The EPA further reported that it is considering the scope of any potential replacement rule.

Federal Coal Leasing Moratorium. The EI Order also lifted the Department of Interior's federal coal leasing moratorium and rescinded guidance on the inclusion of social cost of carbon in federal rulemaking. Following the EI Order, the Interior Secretary issued Order 3349 ending the federal coal leasing moratorium.

Stream Protection Rule. On December 20, 2016, the Office of Surface Mining Reclamation and Enforcement (OSM) issued its final Stream Protection Rule (SPR). The final rule would have impacted both surface and underground mining operations and would have increased testing and monitoring requirements related to the quality or quantity of surface water and groundwater or the biological condition of streams. The SPR would have also required the collection of increased pre-mining data about the site of the proposed mining operation and adjacent areas to establish a baseline for evaluation of the impacts of mining and the effectiveness of reclamation associated with returning streams to pre-mining conditions. Both chambers of Congress passed legislation to repeal and invalidate the rulemaking, pursuant to the Congressional Review Act. The House passed H.J. Res. 38 on February 1, 2017 and the Senate passed the bill the next day. On February 16, 2017, President Trump signed H.J. Res. 38, resulting in the repeal of the SPR and preventing the OSM from promulgating any substantially similar rule. As a result of this repeal, longstanding regulations implementing requirements under the Surface Mining Control and Reclamation Act will continue to govern operations.

Clean Water Act (CWA). The CWA of 1972 directly impacts U.S. coal mining operations by requiring effluent limitations and treatment standards for wastewater discharge from mines through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting and performance standards are requirements of NPDES permits that govern the discharge of water from mine-related point sources into receiving waters.

The U.S. Army Corps of Engineers (Corps) regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the CWA requires mining companies to obtain Corps permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities.

States are empowered to develop and apply "in stream" water quality standards. These standards are subject to change and must be approved by the EPA. Discharges must either meet state water quality standards or be authorized through available regulatory processes such as alternate standards or variances. "In stream" standards vary from state to state. Additionally, through the CWA section 401 certification program, states have approval authority over federal permits or licenses that might result in a discharge to their waters. States consider whether the activity will comply with their water quality standards and other applicable requirements in deciding whether or not to certify the activity.

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A final rule defining the scope of waters protected under the Clean Water Act (commonly called the Waters of the United States (WOTUS Rule), was published by the EPA and the Corps in June 2015. Numerous lawsuits were filed in district courts and courts of appeals nationwide, and all courts of appeals challenges were consolidated in the U.S. Court of Appeals for the Sixth Circuit. District courts in Oklahoma and Georgia dismissed challenges for lack of jurisdiction, but a preliminary injunction was issued by the U.S. District Court in North Dakota in August 2015. On October 9, 2015, the Sixth Circuit stayed the WOTUS Rule nationwide pending further action of the court. On February 22, 2016, a three member panel of the Sixth Circuit held that the Sixth Circuit has exclusive jurisdiction to review challenges to the rule. A request for an en banc hearing was denied. The Tenth and Eleventh Circuits, which are presiding over appeals of the dismissals from Oklahoma and Georgia (respectively), have since stayed proceedings in those appeals. On October 7, 2016, several industry trade organizations and associations filed a petition requesting that the U.S. Supreme Court review the decision of the Sixth Circuit to exercise exclusive jurisdiction over challenges to the rule. The petition was granted on January 13, 2017. On February 28, 2017 the Trump Administration released an executive order directing the EPA and the Corps to consider rescinding or revising the WOTUS Rule, and the EPA and the Corps issued a similar notice that same day. The Department of Justice has notified the courts of this development and has requested that both the Supreme Court and the Sixth Circuit stay all litigation proceedings. The Supreme Court denied that stay request and merits briefing is complete, and oral arguments were held on October 11, 2017. The Sixth Circuit, however, granted the stay request and litigation in that Court is being held in abeyance pending the Supreme Court’s decision. Importantly, the Sixth Circuit’s order holding the case in abeyance did not lift the current nationwide stay against implementation of the WOTUS Rule, and therefore the stay will remain effective during the Supreme Court’s review, which is expected to take until late 2017 or early 2018. If CWA authority is eventually expanded, it may impact our operations in some areas by way of additional requirements. On July 27, 2017, the EPA and the Corps published their proposed rule to rescind the 2015 WOTUS Rule and re-codify the prior definition of “waters of the U.S.” The agencies took public comment on that proposal through September 27, 2017 and could issue a final rule in late 2017 or early 2018.

Mercury and Air Toxic Standards (MATS). The EPA published the final MATS rule in the Federal Register on February 16, 2012. The MATS rule revised the NSPS for nitrogen oxides, sulfur dioxides and PM for new and modified coal-fueled electricity generating plants, and imposed MACT emission limits on hazardous air pollutants (HAPs) from new and existing coal-fueled and oil-fueled electric generating plants. MACT standards limit emissions of mercury, acid gas HAPs, non-mercury HAP metals and organic HAPs. The rule provided three years for compliance with MACT standards and a possible fourth year if a state permitting agency determined that such was necessary for the installation of controls.

Following issuance of the final rule, numerous petitions for review were filed. The D.C. Circuit upheld the NSPS portion of the rulemaking in a unanimous decision on March 11, 2014, and upheld the limits on HAPs against all challenges on April 15, 2014 in a two-to-one decision. Industry groups and a number of states filed and were granted review of the D.C. Circuit decision in the U.S. Supreme Court. On June 29, 2015, the U.S. Supreme Court held that the EPA interpreted the CAA unreasonably when it deemed cost irrelevant to the decision to regulate HAPs from power plants. The court reversed the D.C. Circuit and remanded the case for further proceedings. On December 1, 2015, in response to the court’s decision, the EPA published in the Federal Register a proposed supplemental finding that consideration of costs does not alter the EPA’s previous determination regarding the control of HAPs in the MATS rule. On December 15, 2015, the D.C. Circuit issued an order providing that the rule will remain in effect while the EPA responds to the U.S. Supreme Court decision.

On April 14, 2016, the EPA issued a final supplemental finding that largely tracked its proposed finding. Several states, companies and industry groups challenged that supplemental finding in the D.C. Circuit in separate petitions for review, which were subsequently consolidated. Several states and environmental groups also filed as intervenors for the respondent EPA. Briefing commenced in December 2016 and has now concluded. On April 27, 2017, the D.C. Circuit issued an order which removed the previously scheduled oral argument from the court’s calendar and held the consolidated cases challenging the supplemental finding in abeyance. The order further directed the EPA to file status reports on the agency's review of the supplemental finding every 90 days. The EPA's most recent status report indicates that the EPA is continuing to review the Supplemental Finding "to determine whether the rule should be maintained, modified or otherwise reconsidered" (D.C. Cir. No. 16-1127; July 26, 2017).

Regulatory Matters - Australia

Occupational Health and Safety. State legislation requires us to provide and maintain a safe workplace by providing safe systems of work, safety equipment and appropriate information, instruction, training and supervision. In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under state legislation specific to the coal mining industry. There are some differences in the application and detail of the laws, and mining operators, directors, officers and certain other employees are all subject to the obligations under this legislation.

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A small number of coal mine workers in Queensland and New South Wales have been diagnosed with coal workers' pneumoconiosis (CWP, also known as black lung) following decades of assumed eradication of the disease. This has led the Queensland government to sponsor a review of the system for screening coal mine workers for the disease with a view to improving early detection. The Queensland government has instituted increased reporting requirements for dust monitoring results, broader coal mine worker health assessment requirements and voluntary retirement examinations for coal mine workers to be arranged by the relevant employer and further reform may follow. Peabody has undertaken a review of its practices and offered its Queensland workers the opportunity for additional CWP screening.

The Queensland government held a Parliamentary inquiry into the re-emergence of CWP in the State which included public hearings with appearances by representatives of the coal mining industry, including Peabody, coal mine workers, the Department of Natural Resources and others. The Queensland Parliamentary Committee conducting the inquiry issued an interim report on March 22, 2017 and its final report on May 29, 2017. In finding that it is highly unlikely CWP was ever eradicated in Queensland, the Committee has made 68 recommendations to ensure the safety and health of mine workers. These include an immediate reduction to the occupational exposure limit for respirable coal dust equivalent to 1.5mg/m^3 for coal dust and 0.05mg/m^3 for silica and the establishment of a new and independent Mine Safety Authority to be funded by a dedicated proportion of coal and mineral royalties and overseeing the Mines Safety Inspectorate.

On August 23, 2017, the Queensland Parliament passed the Workers' Compensation and Rehabilitation (Coal Workers' Pneumoconiosis) and Other Legislation Amendment Act 2017, which amends the Workers' Compensation and Rehabilitation Act 2003 by:

- establishing a medical examination process for retired or former coal workers with suspected CWP;
- introducing an additional lump sum compensation for workers with CWP; and
- clarifying that a worker with CWP can access further workers' compensation entitlements if they experience disease progression.

On August 24, 2017, the Queensland Parliamentary Committee released a report containing a draft of the Mine Safety and Health Authority Bill 2017, which proposes to establish the Mine Safety Authority foreshadowed in the Committee's recommendations released in May 2017. The draft bill has been referred to the relevant Parliamentary Portfolio Committee for review.

On September 7, 2017, the Queensland Parliament introduced proposed amendments to legislation which, if passed, will increase civil penalties for mining companies breaching their obligations under the Coal Mining Safety and Health Act 1999. The proposed amendments would also give the Chief Executive of the Department of Natural Resources and Mining new powers to suspend or cancel an individual's statutory certificate of competency and issue site senior executives (SSEs) notices if they fail to meet their safety and health obligations. Higher levels of competency for the statutory position of ventilation officer at underground mines will also be required if the legislation is passed.

Queensland Reclamation. The Environmental Protection Act 1994 (EP Act) is administered by the Department of Environment and Heritage Protection, which authorizes environmentally relevant activities such as mining activities relating to a mining lease through an Environmental Authority (EA). Environmental protection and reclamation activities are regulated by conditions in the EA, including the requirement for the submission of a Plan of Operations (PO) prior to the commencement of operations. All mining operations must be carried out in accordance with the PO which describes site activities and the progress toward environmental and rehabilitation outcomes, and which are updated on a regular basis or if mine plans change. The mines submit an annual return reporting on their EA compliance, including reclamation performance.

As a condition of the EA, bonding requirements are calculated to determine the amount of bonding required to cover the cost of reclamation based on the extent of disturbance during the PO period.

In May 2017, the Queensland government announced broad policy reform proposals in relation to financial assurance (FA) and rehabilitation for the mining and petroleum sector. The proposed regime represents a new approach to managing Queensland’s existing rehabilitation risk management.

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On October 25, 2017, the Queensland Parliament introduced the Mineral and Energy Resources (Financial Provisioning) Bill 2017 (MERFP Bill), which contained proposed legislation to give effect to some of the policy reforms, including:

- a remodeled FA framework that takes into account the financial strength of the EA holder and the risk level of the mine;
- a state-wide pooled FA fund covering most mines and most of the total industry liability;
- discontinuation of prior discounting of FA requirements;
- other options for providing FA for those mines that are not part of the pooled FA fund (for example, allowing insurance bonds or cash);
- updated rehabilitation calculations; and
- regular monitoring and reporting measures for progressive mine rehabilitation.

However, the MERFP Bill lapsed on October 29, 2017 when a Queensland state election was called. The nature of the FA and rehabilitation policy reforms, and the timing for the reintroduction into Parliament of the MERFP Bill or other proposed legislation for implementing those reforms, is dependent on the outcome of the election.

Federal Reclamation. In February 2017, the Australian Senate established a Committee of Inquiry into the rehabilitation of mining and resources projects as it relates to Commonwealth responsibilities, for example, under the Environment Protection and Biodiversity Conservation Act 1999. The Committee is holding public hearings and is currently due to report in during the second quarter of 2018.

Liquidity and Capital Resources

Overview

Our primary sources of cash are proceeds from the sale of our coal production to customers. We have also generated cash from the sale of non-strategic assets, including coal reserves and surface lands. Our primary uses of cash include the cash costs of coal production, capital expenditures, coal reserve lease and royalty payments, debt service costs, capital and operating lease payments, postretirement plans, take-or-pay obligations, post-mining retirement obligations, and selling and administrative expenses. Historically, we have also generated cash from borrowings under our credit facilities and, from time to time, the issuance of securities. We believe that our reorganized capital structure subsequent to the Effective Date will allow us to satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations and cash on hand.

Any future determinations to return capital to stockholders, such as dividends or share repurchases, will be at the discretion of our Board of Directors and will depend on a variety of factors, including the restrictions set forth under our Successor Notes and Successor Credit Agreement, our net income or other sources of cash, liquidity position and potential alternative uses of cash, such as internal development projects or acquisitions, as well as economic conditions and expected future financial results. Our ability to declare dividends or repurchase shares in the future will depend on our future financial performance, which in turn depends on the successful implementation of our strategy and on financial, competitive, regulatory, technical and other factors, general economic conditions, demand for and selling prices of coal and other factors specific to our industry, many of which are beyond our control. See also, Debt Reduction and Shareholder Return Initiatives, below.

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Total Indebtedness. Our total indebtedness as of September 30, 2017 and December 31, 2016 consisted of the following:

	Successor September 30, 2017	Predecessor December 31, 2016
	(Dollars in millions)	
6.00% Senior Secured Notes due March 2022	$ 500.0	$ —
6.375% Senior Secured Notes due March 2025	500.0	—
Senior Secured Term Loan due 2022	645.0	—
2013 Revolver	—	1,558.1
2013 Term Loan Facility due September 2020	—	1,162.3
6.00% Senior Notes due November 2018	—	1,518.8
6.50% Senior Notes due September 2020	—	650.0
6.25% Senior Notes due November 2021	—	1,339.6
10.00% Senior Secured Second Lien Notes due March 2022	—	979.4
7.875% Senior Notes due November 2026	—	247.8
Convertible Junior Subordinated Debentures due December 2066	—	386.1
Capital lease and other obligations	84.0	20.1
Less: Debt issuance costs	(69.9)	(70.8)
	1,659.1	7,791.4
Less: Current portion of long-term debt	47.1	20.2
Less: Liabilities subject to compromise	—	7,771.2
Long-term debt	$ 1,612.0	$ —

Refer to Note 1. “Basis of Presentation” and Note 13. “Long-term Debt” to the accompanying unaudited condensed consolidated financial statements for further information regarding our indebtedness, including our capital structure subsequent to the Effective Date.

Liquidity

As of September 30, 2017, our available liquidity was $942.7 million which was comprised of cash and cash equivalents and availability under our receivables securitization program described below. As of September 30, 2017, our cash balances totaled $925.0 million, including approximately $708.0 million held by U.S. entities, with the remaining balance held by foreign subsidiaries in accounts predominantly domiciled in the U.S. A significant majority of the cash held by our foreign subsidiaries is denominated in U.S. dollars. This cash is generally used to support non-U.S. liquidity needs, including capital and operating expenditures in Australia and the foreign operations of our Trading and Brokerage segment. We do not expect restrictions or potential taxes on the repatriation of amounts held by our foreign subsidiaries to have a material effect on our overall liquidity, financial condition or results of operations.

Subsequent to our emergence from the Chapter 11 Cases our liquidity primarily consists of cash and cash equivalents and the available balances from our accounts receivable securitization program. Our ability to maintain adequate liquidity depends on the successful operation of our business and appropriate management of operating expenses and capital spending. Our anticipated liquidity needs are highly sensitive to changes in each of these and other factors.

The Successor Notes and Successor Credit Agreement

As described in Note 3. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” and Note 13. “Long-term Debt” of the accompanying unaudited condensed consolidated financial statements, on the Effective Date, the proceeds from the 6.00% Senior Secured Notes due March 2022 and the 6.375% Senior Secured Notes due March 2025 (collectively, the Successor Notes) and the Senior Secured Term Loan under the Successor Credit Agreement were used to repay the predecessor first lien obligations. The proceeds from the Successor Notes and the Senior Secured Term Loan, net of debt issuance costs and an original issue discount, as applicable, were $950.5 million and $912.7

million, respectively.

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We voluntarily prepaid $300.0 million of the original $950.0 million loan principal on the Senior Secured Term Loan in $150.0 million installments on July 31, 2017 and September 11, 2017. On September 18, 2017, we entered into an amendment to the Successor Credit Agreement which lowered the interest rate from LIBOR plus 4.50% per annum with a 1.00% LIBOR floor to LIBOR plus 3.50% per annum with a 1.00% LIBOR floor. The amendment permits us to add an incremental revolving credit facility in addition to our ability to add one or more incremental term loan facilities under the Successor Credit Agreement. The incremental revolving credit facility and/or incremental term loan facilities, which remain unutilized, can be in an aggregate principal amount of up to $300.0 million plus additional amounts so long as the Company maintains compliance with the Total Leverage Ratio, as defined in the agreement.The amendment also made available an additional restricted payment basket that permits additional repurchases, dividends or other distributions with respect to our Common and Preferred Stock in an aggregate amount up to $450.0 million so long as our Fixed Charge Coverage Ratio, as defined in the agreement, would not exceed 2.00:1.00 on a pro forma basis.

Interest payments on the Successor Notes are scheduled to occur each year on March 31 and September 30 until maturity. We may redeem the 6.00% Senior Secured Notes beginning in 2019 and the 6.375% Senior Secured Notes beginning in 2020, in whole or in part, and subject to periodically decreasing redemption premiums, through maturity. The Senior Secured Term Loan principal is payable in quarterly installments plus accrued interest through December 2021 with the remaining balance due in March 2022. The loan principal is voluntarily prepayable at 101% of the principal amount repaid if voluntarily prepaid prior to March 18, 2018 (subject to certain exceptions, including prepayments made with internally generated cash) and is voluntarily prepayable at any time thereafter without premium or penalty. The Senior Secured Term Loan may require mandatory principal prepayments of 75% of Excess Cash Flow (as defined in the Successor Credit Agreement) for any fiscal year (commencing with the fiscal year ending December 31, 2018). The mandatory principal prepayment requirement changes to (i) 50% of Excess Cash Flow if our Total Leverage Ratio (as defined in the Successor Credit Agreement and calculated as of December 31) is less than or equal to 2.00:1.00 and greater than 1.50:1.00, (ii) 25% of Excess Cash Flow if our Total Leverage Ratio is less than or equal to 1.50:1.00 and greater than 1.00:1.00, or (iii) zero if the our Total Leverage Ratio is less than or equal to 1.00:1.00. If required, mandatory prepayments resulting from Excess Cash Flows are payable within 100 days after the end of each fiscal year. In certain circumstances, the Senior Secured Term Loan also requires that Excess Proceeds (as defined in the Successor Credit Agreement) of $10 million or greater from sales of our assets be applied against the loan principal, unless such proceeds are reinvested within one year.

Under the Successor Credit Agreement, our annual capital expenditures are limited to $220.0 million, $220.0 million, $250.0 million, $250.0 million, and $300.0 million from 2017 through 2021, respectively, subject to certain adjustments.

In addition to the $450.0 million restricted payment basket provided for under the amendment, the Successor Credit Agreement and Successor Notes allow for $50 million of otherwise restricted payments. Additive to this general limit are certain “builder basket” provisions that may increase the amount of allowable restricted payments, as calculated periodically based upon our operating performance. Beginning on January 1, 2018, the payment of dividends and purchases of our own common stock are permitted under additional provisions of the Successor Notes and the Successor Credit Agreement in an aggregate amount in any calendar year not to exceed $25 million, so long as our Total Leverage Ratio would not exceed 1.25:1.00 on a pro forma basis.

Accounts Receivable Securitization

As described in Note 18. “Financial Instruments and Other Guarantees” of the accompanying unaudited condensed consolidated financial statements, on the Effective Date, we entered into an amended Receivables Purchase Agreement to extend the receivables securitization facility previously in place and expand that facility to include certain receivables from the Company’s Australian operations. The term of the receivables securitization program (Securitization Program) ends on April 3, 2020, subject to certain liquidity requirements and other customary events of default set forth in the Receivables Purchase Agreement. The Securitization Program provides for up to $250 million in funding accounted for as a secured borrowing, limited to the availability of eligible receivables, and may be secured by a combination of cash collateral and the trade receivables underlying the program, from time to time. Funding capacity under the Securitization Program may also be drawn upon for letters of credit in support of other obligations. On June 30, 2017, we entered into an amendment to the Securitization Program to include the receivables of additional Australian operations and reduce the associated fees payable.

At September 30, 2017, we had no outstanding borrowings and $179.5 million of letters of credit drawn under the Securitization Program. The letters of credit were primarily in support of portions of our obligations for reclamation, workers' compensation and postretirement benefits. There was no cash collateral requirement under the Securitization Program at September 30, 2017.

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Reclamation Bonding

As described in Note 18. "Financial Instruments and Other Guarantees" of the accompanying unaudited condensed consolidated financial statements, we are required to provide various forms of financial assurance in support of our mining reclamation obligations in the jurisdictions in which we operate. Such requirements are typically established by statute or under mining permits. Historically, such assurances have taken the form of third-party instruments such as surety bonds, bank guarantees, and letters of credit, as well as self-bonding arrangements in the U.S. In connection with our emergence from the Chapter 11 Cases, we shifted away from extensive self-bonding in the U.S. in favor of increased usage of surety bonds and similar third-party instruments, but have retained the ability to utilize self-bonding in the future, dependent upon state-by-state approval and internal cost-benefit considerations. This divergence in practice may impact our liquidity in the future due to increased cash collateral requirements and surety and related fees.

At September 30, 2017, we had total asset retirement obligations of $636.0 million which were backed by a combination of surety bonds, bank guarantees, letters of credit and restricted cash collateral. Cash collateral balances related to reclamation and other obligations are maintained on our balance sheets within "Investments and other assets," but are excluded from our available liquidity. Such cash collateral amounted to $530.3 million at September 30, 2017, of which $160.1 million was held in the U.S. and $370.2 million in Australia.

Bonding requirement amounts may differ significantly from the related asset retirement obligation because such requirements are calculated under the assumption that reclamation begins currently, whereas our accounting liabilities are discounted from the end of a mine's economic life (when final reclamation work would begin) to the balance sheet date.

Capital Requirements

There were no material changes to our capital requirements from the information provided in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2016, as amended on July 10, 2017 and August 14, 2017.

Contractual Obligations

The consummation of the Plan and related reorganization activities resulted in significant changes to our future contractual obligations with respect to our long-term debt and capital and operating lease obligations which were disclosed in Item 2 of our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017. Our future contractual obligations with respect to our long-term debt have further changed as a result of the principal repayments on our Senior Secured Term Loan and the amendment to our Successor Credit Facility as more fully described in Note 13. "Long-term Debt" to the accompanying unaudited financial statements. Our resulting future long-term debt obligations for periods subsequent to September 30, 2017 are set forth in the table below. The related interest on long-term obligations was calculated using rates in effect at September 30, 2017 for the remaining contractual term of the outstanding borrowings. There were no other material changes to our contractual obligations from the information previously provided in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2016, as amended on July 10, 2017 and August 14, 2017, and Item 2 of our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017.

	Payments Due By Period					
	Total	Three Months Ending December 31, 2017	2018-2019	2020-2021	2022-2023	Subsequent to 2023
	(Dollars in millions)					
Long-term debt obligations (principal and interest)	$2,176.4	$ 25.1	$ 204.5	$ 208.3	$ 1,198.7	$ 539.8

Debt Reduction and Shareholder Return Initiatives

In the second quarter of 2017, we outlined our debt reduction and shareholder return initiatives. The details of these initiatives are as follows:

- Liquidity Targets. Peabody is targeting liquidity of approximately $800 million. This target takes into account variability of pricing and cash flows and the ability to sustain cyclical downdrafts.
- Debt Targets. Peabody is targeting gross debt of $1.2 billion to $1.4 billion over time to enhance the sustainability of its capital structure across all cycles. Peabody is targeting $500 million of debt reduction by December 2018 and made $300 million in voluntary payments of its term loan under the Successor Credit Agreement during the three months ended September 30, 2017.
- Return of Capital to Shareholders. Peabody's board of directors authorized a $500 million share repurchase program. Repurchases may be made from time to time at our discretion. The specific timing, price and size of purchases will depend on the share price, general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time. No expiration date has been set for the repurchase program, and the program may be suspended or discontinued at any time. During the three months ended September 30, 2017, we repurchased approximately 1.5 million shares of our Common Stock for $40.0 million in connection with an underwritten secondary offering and made additional open-market purchases of approximately 1.0 million shares of our Common Stock for $29.2 million. Subsequent to September 30, 2017 and through October 30, 2017, we have purchased an additional 1.3 million shares of our Common Stock for $37.7 million. The purchases were made in compliance with our debt provisions that limit our ability to repurchase shares following the Plan Effective Date.
- Dividends. Peabody's board of directors will regularly evaluate a sustainable dividend program, targeting commencement in the first quarter of 2018. The timing and amount of dividends under such a program will depend on general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time.

Historical Cash Flows

The following table summarizes our cash flows for the period April 2 through September 30, 2017, January 1 through April 1, 2017, and the three and nine months ended September 30, 2016, as reported in the accompanying unaudited condensed consolidated financial statements:

	Successor	Predecessor	
	April 2 through September 30, 2017	January 1 through April 1, 2017	Nine Months Ended September 30, 2016
	(Dollars in millions)		
Net cash provided by (used in) operating activities	330.3	214.0	(276.8)
Net cash (used in) provided by investing activities	(34.9)	15.1	(199.7)
Net cash (used in) provided by financing activities	(424.1)	(47.7)	1,383.0
Net change in cash and cash equivalents	(128.7)	181.4	906.5
Cash and cash equivalents at beginning of period	1,053.7	872.3	261.3
Cash and cash equivalents at end of period	$925.0	$1,053.7	$1,167.8

Cash Flow - Successor

Cash provided by operating activities in the Successor period April 2, 2017 through September 30, 2017 resulted from improved supply and demand conditions leading to increased cash from our mining operations. In addition, $99.4 million of restricted cash collateral became unrestricted. These factors were partially offset by the greater use of working capital related to coal stockpile increases and the payment of claims and professional fees related to the Chapter 11 Cases.

Cash used in investing activities in the Successor period April 2, 2017 through September 30, 2017 resulted from additions to property, plant, equipment and mine development, which was partially offset by repayments of loans from related parties.

Cash used in financing activities in the Successor period April 2, 2017 through September 30, 2017 resulted primarily from $300.0 million of repayments on the Senior Secured Term Loan and $69.2 million of repurchases of Common Stock in accordance with our debt reduction and shareholder return initiatives.

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Cash Flow - Predecessor

Cash provided by operating activities in the Predecessor period January 1, 2017 through April 1, 2017 resulted from year-over-year increase in cash from our operations from improved supply and demand conditions.

Cash used in operating activities during the nine months ended September 30, 2016 resulted from unfavorable supply and demand conditions leading to decreased cash from our mining operations, greater use of working capital, and cash restrictions brought about by increased collateral demands on various obligations.

Cash provided by investing activities in the Predecessor period January 1, 2017 through April 1, 2017 resulted from repayments of loans from related parties and proceeds from disposals of assets driven by the sale of Dominion Terminal Associates, which was offset by payments for additions to property, plant and equipment.

Cash used in investing activities during the nine months ended September 30, 2016 resulted primarily from federal coal lease and other capital expenditures of approximately $305 million, partially offset by proceeds from the disposal of our 5.06% participation interest in the Prairie State Energy Campus, as well as our disposal of interests in undeveloped metallurgical reserve tenements in Queensland’s Bowen Basin, which included the Olive Downs South, Olive Downs South Extended and Willunga tenements.

Cash used in financing activities in the Predecessor period January 1, 2017 through April 1, 2017 resulted from payments of Predecessor deferred financing costs associated with the new Successor debt entered into upon our emergence from the Chapter 11 Cases.

Cash provided by financing activities during the nine months ended September 30, 2016 resulted from proceeds from long-term debt, primarily due to the proceeds received from our Predecessor interim financing facility during the second quarter of 2016 and the net draws on our 2013 Predecessor Revolver during the first quarter of 2016.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to guarantees and financial instruments with off-balance-sheet risk, most of which are not reflected in the accompanying unaudited condensed consolidated balance sheets. We could experience a decline in our liquidity as financial assurances associated with reclamation bonding requirements, bank guarantees, surety bonds or other obligations are required to be collateralized by cash or letters of credit.

Guarantees and Other Financial Instruments with Off-Balance Sheet Risk. See Note 18. “Financial Instruments and Other Guarantees” to our unaudited condensed consolidated financial statements for a discussion of our accounts receivable securitization program and guarantees and other financial instruments with off-balance sheet risk.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with U.S. GAAP. We are also required under U.S. GAAP to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

Our critical accounting policies are discussed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report on Form 10-K for the year ended December 31, 2016, as amended on July 10, 2017 and August 14, 2017. Our critical accounting policies remain unchanged at September 30, 2017, with the exception of the accounting policy elections described in the following paragraph that we made in connection with fresh start reporting. These elections impact the Successor period presented in the accompanying condensed consolidated financial statements and will impact prospective periods.

We will classify the amortization associated with our asset retirement obligation assets within “Depreciation, depletion and amortization” in our consolidated statements of operations, rather than within “Asset retirement obligation expenses”, as in Predecessor periods. With respect to our accrued postretirement benefit and pension obligations, we will prospectively record amounts attributable to prior service cost and actuarial valuation changes, as applicable, currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented
See Note 2. “Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented” to our unaudited condensed consolidated financial statements for a discussion of newly adopted accounting standards and accounting standards not yet implemented.
Item 3. Quantitative and Qualitative Disclosures About Market Risk.
Foreign Currency Risk
We have historically utilized currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 7. “Derivatives and Fair Value Measurements” to the accompanying unaudited condensed consolidated financial statements. Subsequent to the Effective Date, we entered into a series of currency options and, as of September 30, 2017, had currency options outstanding with an aggregate notional amount of approximately $450 million and $675 million Australian dollars to hedge currency risk associated with anticipated Australian dollar expenditures during the remainder of 2017 and the first half of 2018, respectively. Assuming we had no foreign currency hedging instruments in place, our exposure in operating costs and expenses due to a $0.05 change in the Australian dollar/U.S. dollar exchange rate is approximately $95 to $105 million for the next twelve months. Taking into consideration the currency option contracts put into place subsequent to the Effective Date, our net exposure to unfavorable rate changes for the next twelve months is approximately $70 to $80 million.
Other Non-Coal Trading Activities — Diesel Fuel Price Risk
Diesel Fuel and Explosives Hedges. We have historically managed price risk of the diesel fuel and explosives used in our mining activities through the use of cost pass-through contracts and from time to time, derivatives, primarily swaps. As of September 30, 2017, we no longer have any diesel fuel derivative instruments in place.
We expect to consume 125 to 135 million gallons of diesel fuel during the next twelve months. A $10 per barrel change in the price of crude oil (the primary component of a refined diesel fuel product) would increase or decrease our annual diesel fuel costs by approximately $31 million based on our expected usage.
Item 4. Controls and Procedures.
Evaluation of Disclosure Controls and Procedures
Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934, as amended) as of September 30, 2017. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were not effective as of September 30, 2017 because of the material weaknesses in our internal control over financial reporting described below.
All systems of internal control, no matter how well designed, have inherent limitations. Therefore, even those systems deemed to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of a company’s annual or interim consolidated financial statements will not be prevented or detected on a timely basis.
Evaluation of the Internal Control over Financial Reporting
Management determined that the internal control around the reconciliation of tax basis balance sheets to deferred tax balances was not designed effectively and did not operate at a sufficient level of precision to prevent or detect a material misstatement on a timely basis. Specifically, an immaterial misstatement related to deferred tax liabilities of a single taxpayer outside of the consolidated Australian tax paying group was identified, which resulted in the understatement of the income tax valuation allowance required to reduce the carrying value of its deferred tax assets. The Company has subsequently revised its financial statements and related disclosures to correct these errors.
This control deficiency created a reasonable possibility that a material misstatement to the annual consolidated financial statements would not be prevented or detected on a timely basis. Accordingly, management concluded that this control deficiency represents a material weakness.

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Management’s Plans for Remediation

Management has been engaged and will continue to advance remedial activities to address the material weakness described above. We believe the risk of a material weakness in subsequent periods will be mitigated by the implementation of an improved general ledger structure and a comprehensive analysis of all deferred tax positions. Additionally we have revised and enhanced the design of existing controls and procedures to properly apply accounting principles in this area, which includes strengthening our income tax controls with improved documentation standards, training and technical oversight.

The material weakness will not be considered fully remediated until the applicable remedial controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively. We expect that the remediation of this material weakness will be completed prior to the end of fiscal year 2017.

Changes in Internal Control Over Financial Reporting

Other than as discussed above, there have been no changes in internal control over financial reporting during the three months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

We are subject to various legal and regulatory proceedings. For a description of our significant legal proceedings refer to Note 1. “Basis of Presentation,” Note 3. “Emergence from the Chapter 11 Cases and Fresh Start Reporting,” Note 5. “Discontinued Operations,” and Note 19. “Commitments and Contingencies” to the unaudited condensed consolidated financial statements included in Part I, Item 1. “Financial Statements” of this Quarterly Report, which information is incorporated by reference herein.

Item 1A. Risk Factors.

In the third quarter of 2017, there were no significant changes to our risk factors from those disclosed in Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2016 filed with the SEC on March 22, 2017, in Exhibit 99.2 to our Current Report on Form 8-K filed with the SEC on April 11, 2017 and in our Annual Report on Form 10-K/A (Amendment No. 1) for the year ended December 31, 2016 filed with the SEC on July 10, 2017. The Risk Factors described in such Forms 8-K and 10-K/A restate certain Risk Factors included in our Annual Report on Form 10-K and are incorporated by reference herein. In addition to the other information set forth in this Quarterly Report, including the information presented in Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” you should carefully consider those risk factors disclosed in the aforementioned filings, which could materially affect the Company’s results of operations, financial condition and liquidity.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Share Repurchase Programs

On August 1, 2017, we announced that our Board of Directors authorized a share repurchase program to allow repurchases of up to $500 million of the then outstanding shares of our common stock and/or preferred stock (Repurchase Program). Repurchases may be made from time to time at the Company’s discretion. The specific timing, price and size of purchases will depend on the share price, general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time. The Repurchase Program does not have an expiration date and may be discontinued at any time. During the three months ended September 30, 2017, we repurchased approximately 1.5 million shares of our Common Stock for $40.0 million in connection with an underwritten secondary offering and made additional open-market purchases of approximately 1.0 million shares of our Common Stock for $29.2 million. Subsequent to September 30, 2017 and through October 30, 2017, we have purchased an additional 1.3 million shares of our Common Stock for $37.7 million. The purchases were made in compliance with our debt provisions that limit our ability to repurchase shares following the Plan Effective Date. See “Risk Factors — The potential payment of dividends on our stock or repurchases of our stock is dependent on a number of factors, and future payments and repurchases cannot be assured” in Exhibit 99.2 to our

Current Report on Form 8-K filed with the SEC on April 11, 2017.

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Share Relinquishments

We routinely allow employees to relinquish common stock to pay estimated taxes upon the vesting of equity awards and upon the issuance of common stock related to our equity incentive plans. The value of common stock tendered by employees is determined based on the closing price of our common stock on the dates of the respective relinquishments.

Purchases of Equity Securities

The following table summarizes all share purchases for the three months ended September 30, 2017:

Period	Total Number of Shares Purchased (1)	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Dollar Value that May Yet Be Used to Repurchase Shares Under the Publicly Announced Program (In millions)
July 1 through July 31, 2017	215	$ 27.09	—	$ 500.0
August 1 through August 31, 2017	1,476,086	27.10	1,476,014	460.0
September 1 through September 30, 2017	989,306	29.53	987,977	430.8
Total	2,465,607	$ 28.08	2,463,991	

(1) Includes shares withheld to cover the withholding taxes upon the vesting of equity awards, which are not part of the Repurchase Program.

Item 4. Mine Safety Disclosures.

Our “Safety a Way of Life Management System” has been designed to set clear and consistent expectations for safety and health across our business. It aligns with the National Mining Association’s CORESafety® framework and encompasses three fundamental areas: leadership and organization, safety and health risk management and assurance. We also partner with other companies and certain governmental agencies to pursue new technologies that have the potential to improve our safety performance and provide better safety protection for employees.

We continually monitor our safety performance and regulatory compliance. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this Quarterly Report on Form 10-Q.

Item 6. Exhibits.

See Exhibit Index at page 82 of this report.

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EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K.

Exhibit No.	Description of Exhibit
2.1	Order Confirming Debtors' Second Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code on March 17, 2017 (incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K, filed March 20, 2017)
2.2	Debtor's Second Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code as revised March 15, 2017 (incorporated by reference to Exhibit 2.2 of the Registrant's Current Report on Form 8-K, filed March 20, 2017)
3.1	Fourth Amended and Restated Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.1 of the Registrant's Current Report on Form 8-K filed April 3, 2017)
3.2	Certificate of Designation of Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.2 of the Registrant's Current Report on Form 8-K filed April 3, 2017)
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.3 of the Registrant's Current Report on Form 8-K, filed April 3, 2017)
4.1	Specimen of stock certificate representing the Registrant's common stock, par value $0.01 per share (incorporated by reference to Exhibit 4.13 of the Registrant's Registration Statement on Form S-1 filed February 12, 2001)
4.2	Specimen of stock certificate representing the Registrant's Series A Convertible Preferred Stock, $0.01 par value (incorporated by reference to Exhibit 4.2 of the Registrant's Registration Statement on Form S-1 filed April 11, 2017)
4.3	Indenture, dated as of February 15, 2017, between the Peabody Securities Finance Corporation (merged with and into the Registrant on April 3, 2017) and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed February 15, 2017)
4.4	Warrant Agreement, dated as of April 3, 2017, between the Registrant and American Stock Transfer & Trust Company, LLC (incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K, filed April 3, 2017)
4.5	First Supplemental Indenture, dated as of April 3, 2017, among the Registrant, Peabody Securities Finance Corporation, the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.3 of the Registrant's Current Report on Form 8-K, filed April 3, 2017)
10.1	Sixth Amended and Restated Receivables Purchase Agreement, dated as of April 3, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all

	LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K filed April 3, 2017)
10.2	Amendment No. 1 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of the Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of September 18, 2017 (incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed September 18, 2017)
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Security Dividends for the five year period ended December 31, 2016 and the nine-month period ended September 30, 2017
31.1*	Certification of periodic financial report by the Registrant's Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of periodic financial report by the Registrant's Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Executive Officer
32.2*	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Financial Officer

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95*	Mine Safety Disclosure required by Item 104 of Regulation S-K
101*	Interactive Data File (Form 10-Q for the quarterly period ended September, 30, 2017 filed in XBRL). The financial information contained in the XBRL-related documents is “unaudited” and “unreviewed”
*	Filed herewith.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

			PEABODY ENERGY CORPORATION
Date:	November 3, 2017	By:	/s/ AMY B. SCHWETZ
			Amy B. Schwetz Executive Vice President and Chief Financial Officer (On behalf of the registrant and as Principal Financial Officer)

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