EVOLUTION PETROLEUM CORP
Form 10-K
September 27, 2010
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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, 2010

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

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: ¨ 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: ¨ 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, 2009, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $4.37 on the NYSE Amex was $63,301,941.

The number of shares outstanding of the registrant s common stock, par value $0.001, as of September 24, 2010, was 27,441,674.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant s 2010 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

2010 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.

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

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

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

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

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

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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.

Porosity. (of sand or sandstone). The relative volume of the pore space (or open area) compared to the total bulk volume of the reservoir.

Probable reserves. Probable reserves are those 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. *

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.

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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). 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 below.

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.

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Standardized Measure. The Standardized Measure of Discounted Future Net Cash Flows 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 determination of Standardized Measured is in accordance with accounting standards generally accepted in the United States of America (GAAP).

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 is 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 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, 2010, we had ten full-time employees, not including contract personnel and outsourced service providers.

Corporate History of Reverse Merger

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

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

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.

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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:

Delhi Field CO_2 EOR (Enhanced Oil Recovery) Project

Our interests in the Delhi Holt Bryant Unit in the Delhi Field located in Northeast Louisiana are currently our most significant asset. The Unit is currently being redeveloped as an EOR project utilizing CO_2 technology by a subsidiary of Denbury Resources Inc. as Operator.

We own royalty interests in the Unit aggregating 7.4%. The royalties bear no operating or capital cost burdens to us and are in effect throughout the life of the project.

We also own a 23.9% reversionary working interest with an associated 19.2% net revenue interest. The working interest reverts to us when the Operator has generated $200 million of field revenue from the 100% working interest and associated revenue interest, less direct operating expenses including the cost of purchased CO_2. Upon reversion of the deemed $200 million payout, regardless of the Operator s actual capital expenditures, we begin bearing 23.9% of all future operating and capital expense. Also at payout reversion, our net revenue interest increases from 7.4% to 26.6%.

During Fiscal 2010:

- Our independent reservoir engineers, DeGolyer & MacNaughton (D&M) assigned the following net reserves to our interests at Delhi as of June 30, 2010:

- 9.4 MMBBLs of proved oil reserves, with a PV-10 of $224.5 million *

- 5.7 MMBBLS of probable oil reserves, with a PV-10 of $51.2 million *

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* PV-10 of proved reserves is a non-GAAP measure, reconciled to the Standardized Measure of Future Net Cash Flows 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.

- On April 5, 2010, we announced that oil production in the Delhi enhanced oil recovery project (EOR) began in March 2010, approximately three to four months earlier than we expected.

- On November 12, 2009 CO_2 injection commenced.

We believe that the Delhi Holt Bryant Unit is a strong candidate for a CO_2-EOR project due to its favorable rock characteristics, large unproven reserves remaining in place, low cost of drilling due to a relatively shallow depth and relatively close location to naturally occurring CO_2 reserves approximately 100 miles east of the Delhi Field. We base our belief on (i) our internal analyses of CO_2 pilot tests successfully completed in the Delhi Holt Bryant Unit by a prior field operator, (ii) our analysis of favorable analogous comparisons to successful full scale projects in the same or similar geological formation, (iii) a competitive offering process, wherein we solicited multiple major participants with CO_2-EOR expertise, funding and operating abilities, leading to confidential competitive offers made to us in writing, (iv) our qualitative assessment that the competitive offers were based on the CO_2-EOR potential of the Unit and not on the relatively minor associated proved reserves existing at that time, (v) the buyer s willingness to commit a portion of its proved CO_2 reserves and a $100 million minimum future investment, subject to penalties for non-performance, in a CO_2 project in the Unit, (vi) the early oil production response following the initiation of CO_2 injection, and (vii) D&M s reserve assignments.

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According to published reports and field records, the Delhi Field was discovered in the mid-1940 s and was extensively developed by various operators including the Sun Oil and Murphy Oil companies through the drilling and completion of approximately 450 wells, most within the first few years after discovery. According to D&M, an independent reservoir engineering firm experienced in CO_2-EOR projects who is engaged by Denbury and us to review the project, the Delhi Field has produced approximately 192 million barrels of crude oil and substantial amounts of natural gas to date. Much of the natural gas production was processed to remove natural gas liquids and re-injected for pressure maintenance. Beginning in the late 1950 s, the field was unitized to conduct a pressure maintenance project through the injection of water into the producing reservoir in down dip injection wells (unitization is the process of combining multiple leases into a single ownership entity in order to simplify operations and equitably distribute royalties when common operations are conducted over multiple leases). Drilling operations resulted in primarily 40-acre spacing across the unit s 13,636 acres. A few wells were drilled below the targeted Tuscaloosa and Paluxy formations. The water injection pressure maintenance operations did not utilize a more traditional and effective five spot flood pattern water flood that generally results in a more complete reservoir sweep and oil recovery.

At the time we began our oil and natural gas operations in late September 2003, we purchased approximately 95.8% of the working interest in the Delhi Field (from the surface to the top of the Massive Anhydride formation, but excepting the Mengel Unit), for approximately $2.8 million, including the assumption of a plugging and abandonment reclamation bond. All but 43 wells in Richland, Franklin and Madison Parishes, Louisiana had been plugged and abandoned. At that time, production averaged approximately 18 BOPD with no natural gas being sold due to a lack of natural gas processing and transportation facilities. The best producing well was immediately lost during a periodic sand wash work-over when water from a lower reservoir broke through along the casing exterior and into the producing reservoir.

In October of 2003, we applied an unproven lateral re-entry technology that resulted in no increase in production. In December 2003, we initiated a conventional development program based on re-completion of wells to other reservoirs and restoring non-producing wells to producing status. During 2004, we refurbished a gas injection line, converting it to a gas gathering and sales line, and placed a gas processing plant in the field to begin natural gas production in July of 2004. During 2005, we began a five well development drilling program aimed at reaching mostly proved undeveloped reserves left in primary attic positions. The culmination of these activities caused production to increase from 18 BOPD to a monthly average rate of 145 BOEPD during our peak production month in late 2005, at a capital cost of about $2.5 million.

Concurrent with these activities, we completed internal studies indicating that the reservoirs in the Delhi Holt Bryant Unit, the dominant oil producing reservoirs, had substantial remaining recoverable oil in place. Based on positive CO_2 pilots conducted by Sun Oil in 1985, and favorable rock characteristics shown in multiple cores previously taken throughout the Delhi Field, we began discussions in late 2004 with potential industry partners skilled in CO_2-EOR recovery methods,.

During this time we also began to acquire royalty and overriding royalty interests that ultimately aggregated 7.4%, at a capital cost of approximately $1.5 million.

With positive industry reception, and following extended negotiations with three candidates as prospective partners, we accelerated our redevelopment plan in June 2006 by selling all of our working interest in the Holt Bryant Unit, in the form of a Farmout, to Denbury Onshore LLC, a subsidiary of the Operator, and 75% of our working interests in certain other depths of the Delhi Field (the Delhi Farmout). Important aspects of this transaction include:

- We received $50 million in cash (pre-tax) to redeploy to other projects and repay all of our then outstanding debt.

- We retained significant participating interests through a reversionary working interest equal to 23.9% (25% of our original working interest delivered to Denbury), with an associated 19.2% net revenue interest. We expected that the value of these interests (along with the separately acquired mineral royalty and overriding royalty interests aggregating 7.4% would substantially exceed the $50 million cash component of the Delhi Farmout, subject to future oil prices, operating expenses, anticipated EOR performance and project completion by the Operator.

- The Operator committed to install a CO_2-EOR project in the Holt Bryant Unit and expend a minimum additional $100 million on the project over the first 6-1/2 years, subject to penalty payments to us for shortfalls in such expenditures. All capital expenditures related to our interests in the project are borne by the Operator prior to payout.

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- The Operator is the dominant CO_2-EOR operator on the Gulf Coast and owns naturally occurring proved CO_2 reserves that we believe to be sufficient to meet the needs of the Delhi project and which have been dedicated to the Delhi project.

- Our reversionary working interest in the CO_2-EOR project is based on a defined $200 million threshold, subject only to expansion of the project through acquisitions, and our reversionary working interest occurs when cumulative project revenues less direct operating costs in the field reach the threshold. Direct operating costs include an established cost for each purchased Mcf of CO_2 equal to 1% of the price of a barrel of crude oil sold from the Holt Bryant Unit plus $0.20 for transportation. CO_2 injection volumes are primarily from purchases during the initial years of a CO_2-EOR project, and are gradually displaced by cheaper recycling costs (currently about $0.15 per Mcf) later in the project.

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

We began leasing activities in the Giddings Field in December 2006 and acquired 20,899 and 19,147 gross and net acres, respectively, of which 5,027 net acres are developed and 7,255 net acres remain as net undeveloped and associated with our proved and probable drilling locations as of June 30, 2010. 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, 2010, we have placed ten wells into production, including seven wells that were re-entered and re-drilled, one new well that was drilled and two wells that were restored to production through workovers. Total net proved reserves assigned to our properties in the Giddings Field by our independent reservoir engineer, W.D. Von Gonten & Associates, are 2,983 MBOE as of June 30, 2010, a slight decrease of 30 MBOE from June 30, 2009 despite Giddings production during the year of 119.2 MBOE. Our total investment of $26.7 million to date has generated cash flows from 286.3 MBOE of total net production and our proved PV-10 at June 30, 2010 of $41.3 million. In addition, we have two probable drilling locations and probable undeveloped reserves associated with proved drilling locations totaling 978 MBOE with a PV-10 of $11.7 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.

On July 16, 2010, we entered into a joint development agreement (JDA) with an industry partner. The JDA provides that we operate the drilling of two firm commitment wells on our proved and probable locations in the Giddings Field, with the potential to add up to three option wells as elected by our partner. Under the terms of the JDA, we retain a 10% carried working interest in recognition of our costs to date, a 10% cost bearing working interest for our cash participation, and a 22.5% back-in working interest on each well drilled on our partner s 80% working interest following a simple 2 well basket payout and well-by-well simple pay-out on subsequent wells (bringing our after-payout working interest in each well to 38%). The leases carry an approximate 80% net revenue interest to the 100% working interests.

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Lopez Field (Neptune Oil Project)

We acquired 1,721 net acres through leasing in our Neptune Oil Project in the Lopez Field in South Texas. We believe that previous drilling and production in this field by another operator established reserves potential on infill spacing. As of June 30, 2009, our independent reservoir engineer recognized four proved well locations with 47.6 MBO of proved undeveloped reserves on approximately 40 net acres of our holdings. We began field testing late in the second fiscal quarter of 2010 with the drilling of two infill producers and the re-entry of two previously abandoned wells for water injection. Due to delays in obtaining electric power service and mechanical problems with the re-entered injection wells, we were not able to begin effective testing until the fourth quarter of 2010, thus we elected to reclassify the proved reserves as probable as of June 30, 2010. Our independent engineer, W.D. Von Gonten & Associates, has concurred with this position and has assigned 21 additional probable drilling locations. Should further testing warrant full development, we have identified up to 92 additional prospective infill drilling locations in the balance of our leasehold.

Tullos Field

On March 3, 2008, we completed the sale of our properties in the Tullos Field, located in LaSalle and Winn Parishes in Louisiana, for gross cash proceeds of approximately $4.6 million.

Producing about 100 gross and 79 net barrels of oil production per day from over 150 producing wells at the time of our divestiture, the Tullos Field required a disproportionate amount of staff effort and vendor services, thereby adversely affecting our ability to develop other projects utilizing our expertise and working capital, particularly in the Giddings Field. The field produced large volumes of water associated with the oil production after being downsized to only two acre spacing. Furthermore, we believe that the potential upside in the Tullos Field was substantially less than that offered in our other projects, where the cash proceeds from the sale of our properties in the Tullos Field could be expected to yield a much higher return. Last, we had completed the testing of our oil-on-water completion technology utilizing the one well we drilled in the Tullos Field and determined that the potential of that technology could be best realized in other fields with greater potential.

Unconventional Gas Resources

Woodford Shale Projects in 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 well AFE costs in the $200,000 to $2 million range.

- 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 sections of the Woodford Shale in Eastern Oklahoma.

Wagoner County

The Woodford Shale formation in our leasehold in Wagoner County generally lies at a depth of 1200 to 1600 . Our 9,176 net acre leasehold is offset by two operators that have combined to drill commercial wells extensively in the Woodford to date in a much shallower portion of the formation. During 2010, we continued our deliberate testing program with wells in three of our four acreage blocks, tests of the Woodford and Caney formations, and tests of three types of completions including two types of fracs. These tests indicated that:

- The Caney Shale is an incremental target that may add long term value as a secondary target to the Woodford.

- The frac tests, when combined with information obtained from other operators, have better defined optimum completion practices.

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- Henry #19-2 in our western most block was more successful than expected, reaching a peak production rate of 90-100 mcfd before power failures from storms ended the test. Our independent reservoir engineer has assigned proved developed nonproducing reserves of 138 MMCF to the Henry well and further assigned ten offset probable drilling locations (1.4 BCF net) surrounding the well.

- The Knoche well in our southern leasehold block utilized a different completion method and was substantially less productive than expected. A second test well in the leasehold will be required prior to a full development decision regarding this block..

- The Limon well in our eastern leasehold block was tested in the Caney Shale and is currently being prepared for testing in the Woodford Shale.

Haskell County

The Woodford Shale formation in our 8,441 net acre leasehold in Haskell County generally lies at a depth of 4000 to 6000 . Our leasehold is just north of a short horizontal Woodford well with extensive production history that indicates substantial ultimate recovery and good commerciality. As of July 1, 2010, development and production testing had not yet begun on our leasehold, although we plan to begin initial test operations during fiscal 2011.

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. 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 2010, 2009, and 2008.

	Year Ended June 30,		
Customer	**2010**	**2009**	**2008**
Plains Marketing L.P.	12%	40%	67%
Enterprise Crude Oil LLC	31%	5%	
ETC Texas Pipeline, LTD.	19%	36%	26%
DCP Midstream, LP	15%	16%	
Copano Field Services/Upper Gulf Coast, L.P.	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.

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Market Conditions

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

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

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 us. 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.

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Item 1A. Risk Factors

Risks related to the Company

Operating results from oil and natural gas production may decline.

In the near term, our production is totally dependent on ten wellbores at our Giddings Field and our 7.4% royalty interests in EOR production that began at our Delhi Field in March 2010. 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 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 affect 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 and an initial oil production response began in March 2010, 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 render 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. 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, 2010, five purchasers each accounted for all of our oil and natural gas revenues. 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.

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, but a patent application is pending on one of our technologies. 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 be awarded patent protection and may not result in a commercial service or product.

We have developed and field tested our artificial lift technology that we hope to commercialize and 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/or patent protection. Although our patent is pending, there is no assurance that a patent will be awarded or that we will have the ability to exercise patent defense against competitors.

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

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

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

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

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

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

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

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

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

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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.

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 we have. 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.

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The crude oil and natural gas reserves included in this report 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. The reserves discussed in this report 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 previous 12-month average beginning-of-month price and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the crude oil and natural gas industry in general. PV-10 does not necessarily correspond to market value.

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

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

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 and 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 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.

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 83% of our proved reserves at June 30, 2010 are crude oil reserves and 8% 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:

• *Climate Change.* On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. President Obama has indicated his support of legislation to reduce greenhouse emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. The U.S. Environmental Protection Agency (EPA) has also taken recent action related to greenhouse gasses. Based on recent developments, the EPA now purports to have a basis to begin regulating emissions of greenhouse gasses under existing provisions of the federal Clean Air Act. It is not possible at this time to predict whether or when the U.S. Senate may act on climate-change legislation, however any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas that we produce.

• *Taxes.* President Obama s Fiscal Year 2011 Budget Proposal includes provisions that would, if enacted, repeal of the percentage depletion allowance for oil and natural gas properties, eliminate the immediate deduction for intangible drilling and development costs and eliminating the deduction from income for domestic production activities relating to oil and natural-gas exploration and development, and

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• *Hydraulic Fracturing.* The U.S. Congress is 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, and result in continued or increased operating losses. These factors could negatively impact our operations and may limit our growth.

Risks Associated with Our Stock

Our stock prices 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, 2010, our stock price as traded on the NYSE Amex ranged from $2.21 to $6.25. 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 7.0 million shares or approximately 26% of our outstanding common stock. Our former Chairman, and current director of the Board, Mr. Laird Q. Cagan, is a Managing Director of Cagan

McAfee Capital Partners, LLC (CMCP). Mr. Eric McAfee, also a Managing Director of CMCP, currently owns or controls, directly or indirectly, approximately 2.9 million shares, or approximately 11% of our outstanding common stock, but is neither an officer, employee nor a member of our board of directors. Collectively, the two managing directors of CMCP currently own or control, directly or indirectly, approximately 3.2 million shares, or approximately 12% of our outstanding common stock. Institutional affiliates, including JVL Advisors LLC and Peninsula Capital Management, LP, collectively own approximately 6.7 million shares or approximately 25% 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, 2010, the actual daily trading volume in our common stock ranged from 2,795 shares of common stock to a high of 1,097,969 shares of common stock traded, with only 89 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.

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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.

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. 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, 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.

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. Prior to March 1, 2007, we occupied a leased headquarters containing 2,259 square feet in an office building located on the west side of Houston, Texas. In April 2007, this lease expired.

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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 beginning-of-month price for the year, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

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

Estimated future net revenues discounted at 10% or PV-10 is a financial measure that is not recognized by GAAP. We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies. We believe that PV-10 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 below.

Proved Reserves Fiscal Year Ended 2010

Applying the new rules, 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 reserves were classified as proved developed and 91% were classified as proved undeveloped. Classified by product, 83% of our 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 CO_2-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 New York Mercantile Exchange 12-month average beginning-of-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.

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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

We engaged Von Gonten to prepare an independent report of our proved reserves as of 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, we recognized proved reserves of 3,060,040 at June 30, 2009. Of our proved reserves, natural gas represented 35%, natural gas liquids represented 34%, and crude oil represented 31% as of June 30, 2009.

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	Proved

	Developed Producing	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

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Changes in Proved Reserves

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 9,411,841 barrels 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 CO_2 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 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 on June 30, 2010.

	Delhi Field	Giddings Field	Lopez Field	Oklahoma	Total
Proved reserves, MBOE					
July 1, 2009		3,012	48		3,060
Production	(6)	(120)			(126)
Revisions		(13)	(48)		(61)
Improved recovery, extensions and discoveries	9,418	104		23	9,545
June 30, 2010	9,412	2,983		23	12,418

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

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

	For the Years Ended June 30 2010	2009
Estimated future net revenues	$ 571,052,096	$ 58,194,452
10% annual discount for estimated timing of future cash flows	(305,073,753)	(22,368,230)
Estimated future net revenues discounted at 10% (PV-10)	265,978,343	35,826,222
Estimated future income tax expenses discounted at 10%	(104,351,694)	(12,276,431)
Standardized Measure	$ 161,626,649	$ 23,549,791

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 2010	2009
Delhi Field	$ 224,462,846	$
Giddings Field	41,337,594	35,286,887
Lopez Field		539,335

Oklahoma		177,903		
Estimated future net revenues discounted at 10% (PV-10)	$	265,978,343	$	35,826,222
Estimated future income tax expenses discounted at 10%		(104,351,694)		(12,276,431)
Standardized Measure	$	161,626,649	$	23,549,791

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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 table summarizes our total proved reserves as of June 30, 2010 under each of the three assumptions:

	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.

Probable Reserves Fiscal Year Ended 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.

	Oil (MBbls)	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total (MBOE)**		**PV-10**
Probable undeveloped reserves						
Delhi Field	5,682			5,682	$	51,185,283
Giddings Field	206	226	3,272	977	$	11,767,618
Lopez Field	283			283	$	785,921

Oklahoma			1,360	227	$	53,907
Total probable undeveloped reserves	6,171	226	4,632	7,169	$	63,792,729

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

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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, 2010 were 11.3 MMBOE. Future development costs associated with our proved undeveloped reserves at June 30, 2010 totaled approximately $32.9 million. The increase in proved undeveloped reserves is primarily attributable to 8.8 MMBOE of proved undeveloped 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. None of our proved undeveloped locations remain undeveloped for five years from the date of initial recognition as proved undeveloped reserves.

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, 2010			Year Ended June 30, 2009			Year Ended June 30, 2008		
Product	**Volume**		**Price**	**Volume**		**Price**	**Volume**		**Price**
Crude oil (Bbls)	29,749	$	73.56	36,026	$	76.26	29,466	$	99.03
Natural gas liquids (Bbls)	27,820	$	38.80	44,125	$	36.83	10,639	$	63.02
Natural gas (Mcf)	407,674	$	4.30	323,301	$	5.33	69,051	$	9.67

Average production costs, including production taxes, per unit of production (using a six to one conversion ratio of Mcf   s to barrels) were approximately $13, $11 and $25 per BOE for the years ended June 30, 2010, 2009 and 2008, respectively.

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

First EOR oil production at Delhi began in the last two weeks of March 2010. Total sales volumes from Delhi, net to our interest, for the year ended June 30, 2010 was 6,333 Bbls of oil compared to 172 Bbls of oil during the year ended June 30, 2009. Our interests in the Delhi Field consist of more than 76% of our total proved reserves as of June 30, 2010. The average sales price per barrel of crude oil at Delhi was $76.59 for the year ended June 30, 2010, with no associated production costs.

Production from our properties in the Giddings Field decreased 11% from 133,863 BOE during the fiscal year ended June 2009 to 119,182 BOE during the fiscal year ended June 30, 2010. Production of natural gas from our properties in the Giddings Field increased 26%, while production of crude oil and NGLs decreased 31% compared to the year ended June 30, 2009. Our interests in the Giddings Field consist of 24% of our total proved reserves as of June 30, 2010. The average sales price per BOE at Giddings was $38.07 for the year ended June 30, 2010, and associated production costs (not including ad valorem and production taxes) were $12.52 per BOE.

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The increase in volumes from fiscal 2008 to fiscal 2009 were attributable to the development of our properties in the Giddings Field, which accounted for almost 100 percent of our production during the year ended June 30, 2009. Our production in the Giddings Field began late in the third fiscal quarter of the year ended June 30, 2008. Our properties in the Tullos Field, which were sold on March 3, 2008, accounted for 35% of total sales volumes for the year ended June 30, 2008.

Drilling Activity

The following table sets forth our drilling activity.

	Year Ended June 30,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Productive wells drilled						
Development	1.0	1.0	2.0	2.0	6.0	6.0
Exploratory						
Total	1.0	1.0	2.0	2.0	6.0	6.0
Non productive dry wells drilled						
Development						
Exploratory						
Total						

Present Activities

We are currently drilling the Supak-Brinkman-1H in the Giddings Field under of joint development agreement with an industry partner. The Supak-Brinkman-1H is a $1.7 million gross AFE re-entry operation to add a single Austin Chalk lateral to an existing wellbore. We will receive a 10% carried working interest, a 10% cost bearing working interest for our cash participation, and a 22.5% back-in working interest on our partner s 80% working interest.

We are continuing to test the Garcia #1 of our Neptune South Texas Project through a workover.

In Oklahoma, we have temporarily suspended the Henry 19-2 waiting on pipeline connection and we are moving our test of the Limon from the Caney to the Woodford Shale in the same well bore. Further testing of the Knoche 1 and Knoche 2 are pending.

For further discussion, see Highlights for our fiscal year 2010 and Looking forward into 2011 under *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations* of this Form 10-K.

Delivery Commitments

As of June 30, 2010, we had no delivery commitments.

Productive Wells and Developed Acreage

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.

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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.

Our developed acreage at June 30, 2008 totaled 3,469 net acres in the Giddings Field, consisting of a 100% working interest in seven gross and net producing wells.

Undeveloped Acreage

Proved undeveloped acreage includes nineteen proved drilling locations and two probable drilling locations in the Giddings Field.

The reduction of six proved locations from the 25 proved locations as of the end of fiscal 2009 includes the addition of one proved drilling location in Giddings offset by the removal of three drilling locations in Giddings and the reclassification of four drilling locations from proved to probable in the Lopez Field in South Texas. Probable undeveloped acreage includes two drilling locations in Giddings, ten drilling locations in Oklahoma and twenty-five drilling locations in the Lopez Field. Additional drilling locations are associated with our acreage, but require further leasing, step out drilling, and/or an increase in commodity prices before being considered for inclusion.

As of June 30, 2010, we held approximately 55,007 gross and 36,298 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	15,642	13,891
Woodford, Oklahoma	23,925	17,421
Neptune Oil Project (Lopez Field, South Texas)	1,804	1,721
Delhi Field, Louisiana *	13,636	3,265
Total	55,007	36,298

* 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 18,122 acres in fiscal 2011, 4,112 acres in fiscal 2012 and 8,505 acres in fiscal 2013.

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

None.

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, 2010.

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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 2010 and 2009, the high and low sales prices for EPM as reported by the NYSE Amex.

NYSE Amex

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, 2010, there were 27,061,376 shares of common stock issued and outstanding, held by approximately 3,050 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.

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)) (c)
Equity compensation plans approved by security holders	4,445,320(1)	$ 1.90	611,407
Equity compensation plans not approved by security holders	1,196,808(2)	$ 1.60	
Total	5,642,128	$ 1.83	611,407

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(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, 500,000 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, 2010, there were 3,945,320 shares of common stock issuable upon exercise of outstanding stock options, 3,000 options that were exercised and 940,273 shares of common stock issued directly under the 2004 Stock Plan, leaving 611,407 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, 2010 related to these activities were 159,308 with a weighted average exercise price of $1.87. 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

None.

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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.

				Quarter Ended		
		June 30, 2010	March 31, 2010	December 31, 2009	September 30, 2009	June 30, 2009
Revenues						
Crude oil		$ 759,344	$ 469,418	$ 456,375	$ 503,122	$ 409,546
Natural gas liquids (NGLs)		231,460	282,400	280,212	285,311	283,434
Natural gas		368,387	539,563	464,715	381,594	290,971
Total operating revenues		1,359,191	1,291,381	1,201,302	1,170,027	983,951
Operating Expense						
Lease operating expense (LOE)		482,160	399,833	369,928	364,846	379,969
Production taxes		8,054	5,432	16,459	18,367	21,272
Depreciation, depletion, and amortization (DD&A)		144,766	505,445	550,142	617,757	552,153
Accretion expense		15,954	15,562	15,200	14,338	13,149
G&A (excluding stock-based compensation) (1)		433,064	810,171	828,796	861,480	413,132
G&A: Stock-based compensation (2)		957,595	384,701	424,800	391,636	760,365
Total operating expense		2,041,593	2,121,144	2,205,325	2,268,424	2,137,040
Operating loss		(682,402)	(829,763)	(1,004,023)	(1,098,397)	(1,153,089)
Interest income, net		7,269	18,776	13,785	15,224	22,820
Net loss before income tax benefit		(675,133)	(810,987)	(990,238)	(1,083,173)	(1,130,269)
Income tax benefit		245,712	259,466	288,298	378,348	420,627
Net loss		$ (429,421)	$ (551,521)	$ (701,940)	$ (704,825)	$ (709,642)
Loss per share basic and diluted		$ (.02)	$ (.02)	$ (.03)	(.03)	$ (.03)
Weighted average number of common shares outstanding		27,137,611	27,144,174	27,092,954	26,646,022	26,297,444
Sales volumes per day						
Oil (Bbls)		109.5	66.8	66.6	82.3	78.9
NGL (Bbls)		64.2	68.3	74.9	96.4	113.1
Natural gas (Mcf)		972.7	1,082.0	1,188.2	1,210.7	934.1
Total (BOE)		335.8	315.5	339.5	380.5	347.7
Average sales price						
Oil per Bbl		$ 76.18	$ 77.17	$ 74.47	$ 66.46	$ 57.02
NGL per Bbl		39.63	45.42	40.66	32.16	27.55
Natural gas per Mcf		4.16	5.48	4.25	3.43	3.42
Total per BOE		44.47	44.98	38.46	33.43	31.10
Per BOE						
LOE and production taxes		16.04	14.12	12.37	10.95	12.59
DD&A		4.74	17.61	17.61	17.65	17.45
Accretion expense		0.52	0.54	0.49	0.41	0.42
		14.17	28.22	26.53	24.61	13.06

G&A (excluding stock-based compensation) (1)										
G&A: Stock-based compensation (2)		31.33		13.40		13.60		11.19		24.03
Total operating expense		66.80		73.88		70.60		64.80		67.55
Operating (loss) income	$	(22.33)	$	(28.90)	$	(32.14)	$	(31.38)	$	(36.45)
Net income (loss) before income taxes	$	(22.09)	$	(28.25)	$	(31.70)	$	(30.94)	$	(35.72)

(1) G&A for the quarter ended June 30, 2010, includes the reversal of accrued bonuses of $587,033 ($19.21 per BOE of production), due to the decision to issue common stock to employees in lieu of a cash bonus.

(2) G&A: Stock-based compensation for the quarter ended June 30, 2010, includes a charge of $587,033 ($19.21 per BOE of production), related to the payment of 2010 bonuses through the issuance of common stock.

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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 fiscal 2011 development plan from working capital and net cash flows from our properties in the Giddings and Delhi Fields, although we also may utilize appropriate financing to fund additional development above our 2011 development plan.

Highlights for our fiscal year 2010

Oil & Gas Reserves

- **Proved reserves increased 306% to 12.4 million BOE. Proved and probable combined reserves increased 10% to 19.6 million BOE.** This compares to 3.1 million BOE of proved and 17.8 million BOE of proved and probable reserves at June 30, 2009.

- **Proved reserves are 83% oil and 9% liquids, as compared to 31% and 34% at June 30, 2009.**

- **PV-10 of Proved reserves increased 642%, from $36 million to $266 million . PV-10 of proved and probable reserves increased 34%, from $245 million to $330 million.** 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 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.

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- **We added 9.4 million net barrels of proved oil reserves at Delhi. Net proved and probable reserves at Delhi increased 11% to 15.1 million barrels of oil due to greater expected recovery based on the earlier and stronger than anticipated EOR response, and the inclusion of additional pay zones.** Fiscal 2010 was a pivotal year for the Delhi Field. Following four years of field development and $300 million of related capital expended by the Operator, we obtained first EOR production in March 2010, three months earlier than the anticipated mid-summer response date. This early response further supported our independent reservoir engineer s assignment of 15.1 million net barrels of proved and probable oil reserves, 9.4 million of which are classified as proved reserves. Of the 15.1 million net barrels of proved and probable oil reserves approximately five million are associated with our royalty interests. This compares to 13.6 million barrels of probable reserves, and no proved reserves, assigned to Delhi by D&M at the end of fiscal 2009. The current reserve report includes changes to the Delhi EOR development plan that resulted in both positive and negative impacts on our Delhi reserves. The expected future purchase volumes of CO_2 were substantially increased, particularly during the pre-payout period, thereby extending the pre-payout period. In addition, title work by DNR has determined that a small amount of the working interest is owned by third parties, resulting in a minor reduction to our after payout working interest from 25% to 23.9%. These adverse effects are more than offset by three positive revisions. First, the early strong production response, combined with further analysis, have led to a higher expected peak production rate and an increase in the recovery rate from 15% to 17% of original oil in place. Second, D&M has concurred with the expansion of the EOR project to several additional , analogous reservoirs within the field. The combination of these two revisions brings total expected proved and probable gross recoveries to 68 MMBO. Third, reserves now include the benefit of the EOR severance tax holiday granted by the State of Louisiana. For Evolution shareholders, the combination of these effects equates to 1.5 MMBO of added proved and probable reserves and a $79 million increase in PV-10 associated with our proved and probable reserves, offset by an approximate 20 month delay in reversionary payout compared to the 2009 report. At June 30, 2010, proved PV-10 at Delhi is $224.5 million and probable PV-10 is $51.2 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.

- **Our fourth quarter depletion rate of $4.39 per BOE is a proxy for our average historical full-cycle F&D costs.** Since we have never had a ceiling test write-down of our oil and gas properties, our current depletion rate is equal to our average historical, full-cycle finding and development costs for proved reserves.

- **Our proved reserves are 9% developed, but we bear no expected future capital expenditures related to our 8.8 MMBo of proved undeveloped reserves at Delhi.** While less than 10% of Delhi s planned producing wells were online at June 30, 2010, approximately 65% of budgeted project costs had been expended by the Operator through June 30, 2010.

- **Due to delayed testing at our Neptune Oil Project in South Texas, we have elected to revise our 48 MBO of proved undeveloped reserves as probable reserves as of June 30, 2010.** Delay in obtaining power and then unforeseen mechanical difficulties in obtaining adequate saltwater injection capacity delayed the start of our production testing to the fourth fiscal quarter. We will continue to test the project through a workover of the existing producer and re-entry of potentially two additional producer wells during fiscal 2011.

- **We made progress with our first producing test well in our shallow Woodford shale project in Wagoner County, OK, establishing 1.6 BCF of proved and probable reserves in and around the Henry 19-2 vertical test well.** In late February we began steady-state production by flaring production from the Henry. Production steadily increased from an initial low rate as the localized area of the reservoir dewatered. At the end of April, water rates were decreasing while gas production rates were increasing past our targeted peak rate of 80 Mcfd, reaching a rate of 93 Mcfd of gas before the well was shut in due to power failure due to lightning. Although we are unable to predict the final peak gas rate capability of this well, we believe this result is very encouraging and suggests that the dewatering process relieves the hydrostatic formation pressure to allow increasing gas rates, typically followed by a long slow decline curve. An additional test well was put on production in the southern block of our Wagoner leasehold with a different frac application and was disappointing. We expect to again test this block in a different location using the frac utilized in the Henry well. As previously reported, in a separate well we also performed a brief production test of the Caney Shale and determined its modest economic potential to be limited to an add-on to the Woodford Shale.

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- **We replaced 76% of our 120 MBOE net production at the Giddings Field in Central Texas and ended the fiscal year with proved reserves of 3.0 MMBOE and probable reserves of 1.0 MBOE.** Due to upgrading of our portfolio of drilling locations, proved PV-10 at Giddings increased 17% from the prior year to $41.3 million. See *Looking Forward to 2011* for a discussion of the joint development agreement entered into subsequent to our year ended June 30, 2010. 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.

Operations

- **First tertiary oil production began at Delhi in March 2010.** Our share of production from Delhi, net to our royalty interests for the year ended June 30, 2010, was 6,333 Bbls of oil compared to 172 Bbls of oil during the year ended June 30, 2009. In June, gross field production was slightly over 800 BOPD. Denbury is continuing its multi-year roll out of the project by installing Phase II and Phase III in the field through the addition of producer and injector wells and associated facilities in the field, which is expected to provide a continued steady increase in oil production. Once Denbury has generated sufficient net revenues to offset direct operating expenses of the project by the deemed $200 million payout, we will receive a 23.9% working interest (25% of Denbury s interest), and an incremental estimated 19.2% revenue interest (increasing our revenue interest to 26.56%). We expect to continue bearing no capital expenditures or operating costs until such payout occurs, after which we begin paying our working interest share of future costs.

- **Sales volumes decreased 6% in fiscal 2010 versus fiscal 2009.** Our decrease in sales volumes for the year was solely attributable to our normal production decline in the Giddings Field. Production from our properties in the Giddings Field decreased 11% from 133,863 BOE during the fiscal year ended June 2009 to 119,182 BOE during the fiscal year ended June 30, 2010. Production of natural gas from our properties in the Giddings Field increased 26%, while production of crude oil and NGLs decreased 31% compared to the year ended June 30, 2009. First EOR oil production at Delhi began in the last two weeks of March 2010. Our net production from Delhi for the year ended June 30, 2010 was 6,333 Bbls of oil compared to 172 Bbls of oil during the year ended June 30, 2009.

- **We lowered our depletion rate 75% to less than $5 per BOE during the fourth quarter of fiscal 2010.** Our depletion rate for the fourth quarter of fiscal year 2010 was $4.39 per BOE, compared to $17.61 for the third quarter of 2010. The decrease in our depletion rate was due to the addition of 9.4 million barrels of proved oil reserves at Delhi, while associated legacy capital costs of only $1.2 million ($0.13 of costs per incremental barrel) were transferred to our full cost pool.

- **The product prices we received declined 12% in fiscal 2010 versus fiscal 2009.** During the year ended June 30, 2010, the average price we received was $40.01 per BOE, as compared to $45.47 per BOE during the year ended June 30, 2009.

Finances

- **We ended the year with $4.9 million of working capital, compared to $7.6 million at June 30, 2009.** At June 30, 2010, working capital included $4.5 million of cash, cash equivalents and short-term certificates of deposit, and $0.7 million of recoverable income taxes arising from current year tax losses carried back to a prior tax year. The $2.7 million reduction in our working capital since June 30, 2009 was due primarily to investments of $3.8 million in oil and natural gas properties, offset by positive cash flow generated from our oil and gas properties

- **Cash flows from operations covered our general and administrative expenses and funded a portion of our capital expenditures.** Cash flows from operations were $2.3 million during the year ended June 30, 2010, which includes $2.1 million received in January 2010 from the Internal Revenue Service as a result of a carry-back of our tax loss for the year ended June 30, 2009.

- **Non-cash stock-based compensation expense of $2.1 million comprised over 42% of G&A for fiscal year 2010.** Non-cash stock-based compensation expense remains an important part of our total compensation program to help motivate and retain high performing employees and consultants, in addition to conserving our cash resources.

- **We nearly completed negotiations with an industry partner to help finance the resumption of development drilling at Giddings.** For details, see the Looking Forward section below.

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- **We filed a universal shelf registration with the SEC.** With considerable market price volatility becoming more common, we view a shelf registration as an important part of prudent capital management.

- **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 2011

Our Base Case capital budget of $4 million will focus on selective low cost testing and development of our current portfolio properties within the following major operations:

- **Continue the roll out of the CO_2 EOR project at Delhi that is operated and funded by Denbury.** The Operator is continuing development activities through its installation of Phases II and III that began earlier in calendar 2010, and the rate of CO_2 injection has continued to increase. Further roll out is expected to continue during our fiscal 2011. Gross oil production, and our resulting net production from our royalty interests, is expected to substantially increase during the year accordingly.

- **Resume development drilling at Giddings on up to 5 of our 19 proved and 2 probable drilling locations.** Immediately following the close of our recently completed fiscal year, we entered into a joint development agreement (JDA) with an industry partner. The JDA provides that we operate the drilling of two firm commitment wells on our proved locations in the Giddings Field, with the potential to add up to three option wells as elected by our partner. Under the terms of the JDA, we will receive a 10% carried working interest in recognition of our costs to date, a 10% cost bearing working interest for our cash participation, and a 22.5% back-in working interest on each well drilled on our partner s 80% working interest following a simple 2 well basket payout and well-by-well simple pay-out on the subsequent wells (bringing our after-payout working interest to 38%). The leases carry approximately 80% net revenue interest to the 100% working interest.

The first location, the Supak-Brinkman-1H located in Burleson County, is a $1.7 million gross AFE re-entry operation to add a single Austin Chalk lateral to an existing wellbore. We began operations on this location in late August, 2010. We expect to follow with drilling operations on a $2.9 million gross AFE grass roots location (new well), the Dodd, in northern Grimes County to complete two 4,000 opposing laterals into the Georgetown formation. Our outside engineers have assigned to the 100% working interest approximately 164,000 net BOE of proved reserves to the Supak and 244,000 net BOE of reserves to the Dodd. The Dodd reserves are split evenly between proved and probable reserve categories. Our share of expected net capital expenditures for the JV program is $1.18 million, assuming all five wells are drilled. We are also exploring opportunities to enter into a second joint venture to develop additional drilling locations, which would require an increase in our capital subject to the terms of such joint venture.

- **Increase our Woodford Shale test activity.** We plan to complete up to two more test wells at our shallow 1,500 depth Woodford acreage block in Wagoner County, OK during fiscal 2011 to add to our knowledge base. Separately, in our mid-depth Haskell County, OK, Woodford Shale leasehold, we expect to begin re-entry operations on the first of a two vertical well program to begin testing vertical completions in the Woodford between 4,000 and 6,000 depth. We intend to use the information gained to attract candidates for joint venture development.

- **Pursue commercial joint ventures utilizing our proprietary artificial lift technology.** Based on tests results at Giddings, we believe our technology could re-establish production in many wells throughout Giddings and other fields developed with horizontal wells where liquids are associated with their production. We are currently negotiating with a major producer at Giddings, and have entered into discussions with a second producer, to provide our lift technology with the intent of gaining an interest in the newly re-established production. We also plan on approaching other producers during fiscal 2011 for potential applications both within and outside of Giddings.

- **Continue testing of our Neptune Oil Project in South Texas**. Now that adequate water injection capacity exists in the field, we plan to conduct a workover on the Garcia #1 producer to re-complete in a different portion of the Mirando Sand and re-enter up to two additional producer wells to complete our testing program.

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- **Exercise lease options and renew other leases.** We plan to exercise lease options and renew other leases to maintain high value drilling locations at Giddings and our leasehold in Oklahoma, as well as provide funds for forced pooling associated with producing Woodford wells in Oklahoma.

Continued conservative financial management.

- **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.**

- **Primarily use internally generated funds and our working capital to achieve our goals for fiscal 2011.** We may accelerate our development operations where warranted by utilizing joint ventures, project financing, selective divestments of noncore assets or minor equity offerings at attractive stock valuations when capital market conditions improve.

- **Improve financial results through reductions in depletion expense and expected increases in Delhi production.** The fourfold increase in proved reserves, without a substantial increase in future capital costs, is expected to dramatically reduce our depletion expense in future periods. When combined with our expected revenue growth from our Delhi royalty interests bearing no future operating expense or incremental expenditures for capital, our financial results are expected to improve.

Liquidity and Capital Resources

At June 30, 2010, our working capital was $4.9 million and we continued to be debt free. This compares to working capital of $7.6 million at June 30, 2009. The $2.7 million decrease in working capital since June 30, 2009, was due primarily to investments of $3.7 million in oil and natural gas properties (not including $0.1 million incurred related to recognition of asset retirement obligations). Of the $3.7 million of incurred capital expenditures during the year ended June 30, 2010, $0.5 million was for leasehold acquisitions and $3.2 million was for development activities. Development activities were in the Giddings Field in Texas, our Neptune Oil Project in the Lopez Field in South Texas, and our gas shale project in Eastern Oklahoma.

Cash Flows from Operating Activities

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 provided by operating activities for the year ended June 30, 2009 were $6.0 million. Cash flows provided by operations for fiscal year ended June 30, 2009 included cash proceeds of $7.3 million from oil and natural gas production, primarily from our properties in the Giddings Field, cash proceeds of $0.1 million from interest income and cash proceeds of $4.1 million from income tax refunds, primarily from our 2008 tax year net operating loss carry-back. Sources of cash were offset by $5.5 million of cash payments for operating activities, including lease operating expenses, production taxes, salaries and wages and general administrative expense.

Cash Flows from Investing Activities

Cash paid for oil and gas capital expenditures during the year ended June 30, 2010 and 2009, was $3.8 million and $10.7 million, respectively, which includes net payments on accounts payable of $0.1 million and $2.1 million, respectively, relating to prior period expenditures for oil and natural gas properties.

We purchased $1.4 million and $1.8 million in short-term certificates of deposit during the year ended June 30, 2010 and 2009, respectively. During the year ended June 30, 2010, $2.1 million of certificates of deposit matured.

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Cash Flows from Financing Activities

There were no significant cash flows from financing activities during the year ended June 30, 2010. During the previous fiscal year, on October 30, 2008, we repurchased 788,200 shares of common stock at an average price of $1.10 per share plus $0.02 in transaction costs from an unaffiliated accredited investor.

Capital Budget

For our fiscal 2011 Plan, we expect to incur capital expenditures of approximately $4.0 million (for expenditure details, see the   Looking Forward   section above).

We expect to fund our fiscal 2011 Plan with internally generated funds, our working capital and the JDA we signed in July 2010. Increases in our activity level over the planned operations will be funded from joint ventures, project financing, selective divestments of noncore assets or potentially from minor equity offerings at attractive stock valuations when capital market conditions improve.

Results of Operations

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

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

	Year Ended June 30 2010		2009		Variance	% change
Sales Volumes, net to the Company:						
Crude oil (Bbl)		29,749		36,026	(6,277)	(17)%
NGLs (Bbl)		27,820		44,125	(16,305)	(36)%
Natural gas (Mcf)		407,674		323,301	84,373	26%
Crude oil, NGLs and natural gas (BOE)		125,515		134,035	(8,520)	(6)%
Revenue data:						
Crude oil	$	2,188,259	$	2,747,494	$ (559,235)	(20)%

NGLs		1,079,383		1,625,063		(545,680)	(34)%
Natural gas		1,754,259		1,722,626		31,633	2%
Total revenues		5,021,901	$	6,095,183	$	(1,073,282)	(18)%
Average price:							
Crude oil (per Bbl)	$	73.56	$	76.26	$	(2.70)	(4)%
NGLs (per Bbl)		38.80		36.83		1.97	5%
Natural gas (per Mcf)		4.30		5.33		(1.03)	(19)%
Crude oil, NGLs and natural gas (per BOE)	$	40.01	$	45.47	$	(5.46)	(12)%
Expenses (per BOE)							
Lease operating expenses and production taxes	$	13.27	$	10.69	$	2.58	24%
Depletion expense on oil and natural gas properties (a)	$	14.10	$	18.07	$	(3.97)	(22)%

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

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

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

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

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

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

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

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

Depreciation, Depletion & Amortization Expense (DD&A). DD&A decreased by 26% to $1,818,110 for year ended June 30, 2010, compared to $2,461,162 for the year ended June 30, 2009. The decrease is primarily due to a 6% decrease in net sales volumes, and a lower annual depletion rate ($14.10 vs. $18.07) per BOE.

Our depletion rate for the fourth quarter of fiscal year 2010 was $4.39 per BOE compared to $17.23 for the 3rd quarter of 2010, due to the addition of 9.4 million proved oil reserves at Delhi with associated legacy costs of only $1.2 million transferred to our full cost pool. The lower fourth quarter rate is the primary cause of the lower annual depletion rate.

Interest Income. Interest income for the year ended June 30, 2010 decreased $67,218 to $55,054, compared to $122,272 for the year ended June 30, 2009. 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. Product prices, operating costs and development costs may not always move in tandem.

Known Trends and Uncertainties. While general worldwide economic conditions improved during fiscal 2010, they 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.

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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.

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, 2010, our total unevaluated costs were $7.9 million. If these costs were evaluated and included in our full cost pool, with no increases in our proved reserves as of June 30, 2010, our depreciation, depletion and amortization expense would have increased by approximately $20 thousand.

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, 2010, 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, 2010 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $7 thousand, $16 thousand, and $25 thousand, 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, allow companies to disclose their probable and possible reserves to investors, require reporting of oil and gas reserves using an average price based on the prior 12-month period 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 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, 2010, 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, 2010.

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.

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Item 8. Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Evolution Petroleum Corporation

Houston, Texas

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation as of June 30, 2010 and 2009 and the related consolidated statements of operations, stockholders equity, and cash flows for each of the two years in the period ended June 30, 2010. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated 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 audits 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 consolidated financial position of Evolution Petroleum Corporation as of June 30, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the two years in the period ended June 30, 2010 in conformity with accounting principles generally accepted in the United States of America.

We were not engaged to examine management s assertion about the effectiveness of Evolution Petroleum Corporation s internal controls over financial reporting as of June 30, 2010 included in the accompanying Management s Report on Internal Control over Financial Reporting and, accordingly, we do not express an opinion thereon.

HEIN & ASSOCIATES LLP

Houston, Texas

September 27, 2010

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2010	June 30, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 3,138,259	$ 3,891,764
Certificates of deposit	1,350,000	2,059,147
Receivables		
Oil and natural gas sales	536,366	532,318
Income taxes	25,200	
Other	147,059	172,314
Income taxes recoverable	716,973	2,055,802
Prepaid expenses and other current assets	315,494	162,441
Total current assets	6,229,351	8,873,786
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties full-cost method of accounting, of which $7,851,068 and $9,819,465 at June 30, 2010 and 2009, respectively, were excluded from amortization.	30,803,061	28,751,178
Other property and equipment	101,998	150,697
Total property and equipment	30,905,059	28,901,875
Other assets	60,665	53,162
Total assets	$ 37,195,075	$ 37,828,823
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 678,609	$ 690,639
Accrued payroll	75,692	71,427
Royalties payable	221,062	218,477
State taxes payable	202,334	157,736
Other current liabilities	110,002	99,625
Total current liabilities	1,287,699	1,237,904
Long term liabilities		
Deferred income taxes	2,949,880	3,721,317
Asset retirement obligations	811,635	664,710
Stock-based compensation (Note 6 and 15)	587,033	370,440
Deferred rent	81,635	77,858
Total liabilities	5,717,882	6,072,229

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 27,849,576 shares; outstanding 27,061,376 shares and 26,530,317 shares as of June 30, 2010 and 2009, respectively.		27,849		27,318
Additional paid-in capital		18,532,643		16,424,868
Retained earnings		13,798,723		16,186,430
		32,359,215		32,638,616
Treasury stock, at cost, 788,200 shares as of June 30, 2010 and June 30, 2009.		(882,022)		(882,022)
Total stockholders equity		31,477,193		31,756,594
Total liabilities and stockholders equity	$	37,195,075	$	37,828,823

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Year Ended June 30, 2010	Year Ended June 30, 2009
Revenues		
Crude oil	$ 2,188,259	$ 2,747,494
Natural gas liquids	1,079,383	1,625,063
Natural gas	1,754,259	1,722,626
Total revenues	5,021,901	6,095,183
Operating Costs		
Lease operating expenses	1,616,767	1,281,989
Production taxes	48,312	158,794
Depreciation, depletion and amortization	1,818,110	2,461,162
Accretion of asset retirement obligations	61,054	37,601
General and administrative expenses *	5,092,243	5,896,366
Total operating costs	8,636,486	9,835,912
Loss from operations	(3,614,585)	(3,740,729)
Other income		
Interest income	55,054	122,272
Net loss before income tax benefit	(3,559,531)	(3,618,457)
Income tax benefit	1,171,824	1,016,864
Net loss	$ (2,387,707)	$ (2,601,593)
Loss per common share		
Basic and Diluted	$ (0.09)	$ (0.10)
Weighted average number of common shares outstanding		
Basic and Diluted	27,004,066	26,461,057

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

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flow

	Year Ended June 30, 2010	2009
Cash flows from operating activities		
Net loss	$ (2,387,707)	$ (2,601,593)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,818,110	2,461,162
Stock-based compensation	2,148,400	2,405,900
Issuance of common stock for charitable donation		28,600
Accretion of asset retirement obligations	61,054	37,601
Settlement of asset retirement obligations		(90,761)
Deferred income taxes	(771,437)	819,388
Deferred rent	3,777	3,777
Other assets	5,717	6,236
Changes in operating assets and liabilities:		
Receivables from oil and natural gas sales	(4,048)	1,533,982
Receivables from income taxes and other	1,512,041	1,963,436
Prepaid expenses and other current assets	(153,053)	108,497
Accounts payable and accrued expenses	65,144	(624,333)
Royalties payable	2,585	(254,850)
Income taxes payable	44,598	157,736
Net cash provided by operating activities	2,345,181	5,954,778
Cash flows from investing activities		
Development of oil and natural gas properties	(3,280,425)	(8,063,465)
Acquisitions of oil and natural gas properties	(517,530)	(2,603,098)
Capital expenditures for other equipment		(28,635)
Maturities of certificates of deposit	2,059,147	
Purchases of certificates of deposit	(1,350,000)	(1,757,312)
Other assets	(13,220)	(4,715)
Net cash used in investing activities	(3,102,028)	(12,457,225)
Cash flows from financing activities		
Proceeds from issuance of restricted stock	42	130
Proceeds from the exercise of stock options	3,300	
Purchase of treasury stock		(882,022)
Other		3,823
Net cash provided by (used in) financing activities	3,342	(878,069)
Net decrease in cash and cash equivalents	(753,505)	(7,380,516)
Cash and cash equivalents, beginning of period	3,891,764	11,272,280
Cash and cash equivalents, end of period	$ 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, 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

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, 2010 and 2009, 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

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, 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 five 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 five 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.

On December 31, 2008, the SEC released new requirements for reporting oil and gas reserves (the Modernization Requirements). The Modernization Requirements, when effective, provide for consideration of current technology in evaluating reserves, allow companies to disclose their probable and possible reserves to investors, require reporting of oil and gas reserves using an average price based on the prior 12-month period rather than period-end prices, revise the disclosure requirements for oil and gas operations, and revise accounting for the limitation on capitalized costs for full cost companies. The Modernization Requirements are effective for fiscal years ending on or after December 31, 2009. A company may not apply the Modernization Requirements to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. The Modernization Requirements did not have material affect on our financial statements.

The SEC staff issued Staff Accounting Bulletin (SAB) 113 (SAB 113), which revises portions of the guidance included in SAB Topic 12, *Oil and Gas Producing Activities.* Specifically, SAB 113 revises the relevant interpretive guidance in SAB Topic 12 to conform it to the Modernization Requirements.

On January 6, 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2010-03 *Extractive Activities - Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures*, an update of ASC Topic 932 *Extractive Activities - Oil and Gas* (Topic

932), which substantially aligns the reserve estimation, disclosure requirements, and definitions of Topic 932 with the disclosure requirements of the Modernization Requirements issued by the SEC.

EPS

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4 Property and Equipment

As of June 30, 2010 and June 30, 2009 our oil and natural gas properties and other property and equipment consisted of the following:

		June 30, 2010		June 30, 2009
Oil and natural gas properties				
Property costs subject to amortization	$	27,775,641	$	21,985,950
Less: Accumulated depreciation, depletion, and amortization		(4,823,648)		(3,054,237)
Unproved properties not subject to amortization		7,851,068		9,819,465
Oil and natural gas properties, net	$	30,803,061	$	28,751,178
Other property and equipment				
Furniture, fixtures and office equipment, at cost		260,476		260,476
Less: Accumulated depreciation		(158,478)		(109,779)
Other property and equipment, net	$	101,998	$	150,697

Unproved properties not subject to amortization includes unevaluated acreage of $6.0 and $7.5 million as of June 30, 2010 and June 30, 2009, respectively, consisting of 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). Unproved properties include $0.7 million and $2.0 million as of June 30, 2010 and June 30, 2009, respectively, 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 also include $1.2 million and $0.3 million as of June 30, 2010 and 2009, respectively, related to the drilling of three test wells and re-entry of four test wells on our acreage in Wagoner County in Oklahoma. Production testing of our wells in Oklahoma is ongoing. Development of our unproved properties is expected to be completed within one to five years. 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, 2010, by the fiscal year in which the costs were incurred:

					During the Year Ended June 30,					
Costs excluded from amortization		**Total**		**2010**		**2009**		**2008**		**2007**
Leasehold acquisition costs and other	$	5,957,924	$	158,586	$	1,135,971	$	3,847,312	$	816,056
Royalty and overriding royalty interests		735,627				3,636				731,991
Test drilling (exploration)		1,157,517		865,211		292,306				
	$	7,851,068	$	1,023,797	$	1,431,913	$	3,847,312	$	1,548,047

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, 2010 and 2009:

	Year Ended	
	2010	2009
Asset retirement obligations beginning of period	$ 664,710	$ 215,056
Liabilities incurred	85,871	238,702
Liabilities settled		(90,761)
Accretion	61,054	37,601
Revisions to previous estimates		264,112
Asset retirement obligations end of period	$ 811,635	$ 664,710

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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.

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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.

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 and 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, as of June 30, 2010, 611,407 shares remain available for grant under the 2004 Stock Plan.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7 Stock-Based Incentive Plan (Continued)

Offer to Exchange

The extreme financial market volatility encountered during fiscal 2009 caused us to reassess the continued effectiveness of our outstanding stock options granted to employees for the purposes of retention and equity participation. Based on management s analysis and considerable review, our Board of Directors approved an exchange offer to employees with out-of-the-money options, excluding Executive Officers and Directors. Under the terms of the offer, each eligible option to purchase 1.727 shares could be exchanged for one share of restricted common stock. In return, the company and shareholders benefited by (i) re-establishing the retention incentive for nonexecutive employees, (ii) adding one additional year of vesting to all awards exchanged, as further described below, (iii) reduced dilution as the number of restricted shares issued was substantially less than the options exchanged and the exchanged options were returned to the 2004 Plan, and (iv) spread the expense of the incentives over a longer period of time.

Accordingly, we filed a Tender Offer Statement on Schedule TO with the SEC on May 15, 2009, and amendments on May 21, 2009, June 9, 2009, and a final filing on July 2, 2009 announcing termination of the offer, relating to an offer by us to certain employees (excluding Named Executive Officers) to exchange certain outstanding Stock Options granted under the 2004 Stock Plan, with shares of Restricted Stock (the Offer to Exchange). The Offer to Exchange expired on June 19, 2009 (the Expiration Date). Pursuant to the Offer to Exchange, 449,390 eligible Stock Options were tendered and subsequently cancelled, representing 54% of the total Stock Options that were eligible for exchange in the Offer to Exchange. The shares of common stock that were subject to the cancelled Stock Options will be available for future awards under our 2004 Stock Plan. On June 19, 2009 the Company granted an aggregate of 260,170 shares of Restricted Stock in exchange for the Stock Options surrendered in the Offer to Exchange.

We will recognize the unrecognized compensation cost associated with the 449,390 Stock Options cancelled pursuant to the Offer to Exchange of approximately $1,068,430 along with the incremental compensation cost of $78,891 ratably over the vesting period of the Restricted Stock. The incremental compensation, determined on June 19, 2009, was measured as the excess of the fair value of the Restricted Stock granted in the Offer to Exchange, over the fair value of the Stock Options surrendered prior to cancellation. The price of our common stock as of June 19, 2009 was $2.85, however, due to the stock-based compensation requirements, we will recognize expense ratably over the vesting period of the Restricted Stock granted in the Offer to Exchange of approximately $4.41 per share.

The shares of Restricted Stock granted in the Offer to Exchange were unvested at the time of grant and will become vested on the basis of continued service with the Company in accordance with and subject to the terms of the Offer to Exchange as follows: If and to the extent the Stock Options surrendered were vested on the Expiration Date, the Restricted Stock exchanged for those vested Stock Options will become vested on the first anniversary of the Expiration Date, being June 19, 2010. If and to the extent any Stock Options surrendered were not vested on the Expiration Date the Restricted Stock exchanged for those unvested Stock Options will become vested on the first anniversary of the original vesting dates on which such unvested Stock Options would have otherwise become vested. The Restricted Stock granted pursuant to the Offer to Exchange will vest over a weighted average period of approximately four years.

Stock Options and Incentive Warrants

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

There were no Stock Options granted during the year ended June 30, 2010. 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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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7 Stock-Based Incentive Plan (Continued)

	Year Ended June 30, 2010		2009
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, 2010, 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, 2009	5,485,820	$	1.83			
Granted						
Exercised	(3,000)	$	1.10			
Cancelled or forfeited						
Expired						
Stock Options and Incentive Warrants outstanding at June 30, 2010	5,482,820	$	1.83	$	17,421,302	5.4

Vested or expected to vest at June 30, 2010	5,482,820	$	1.83	$	17,235,235	5.4
Exercisable at June 30, 2010	4,930,238	$	1.72	$	16,235,235	5.3

(1) Based upon the difference between the market price of our common stock on the last trading date of the period ($5.01 as of June 30, 2010) and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

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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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7 Stock-Based Incentive Plan (Continued)

A summary of the status of our unvested Stock Options and Incentive Warrants as of June 30, 2010 and the changes during the year ended June 30, 2010, is presented below:

	Number of Stock Options and Incentive Warrants	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2009	1,091,912	$ 1.97
Granted		
Vested	(539,330)	$ 1.90
Forfeited		
Unvested at June 30, 2010	552,582	$ 2.04

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

The total unrecognized compensation cost at June 30, 2010, relating to non-vested Stock Options and Incentive Warrants was $1,069,075. Such unrecognized expense is expected to be recognized over a weighted average period of 1.5 years.

Restricted Stock

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

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2010:

	Number of Restricted Shares		Weighted Average Grant-Date Fair Value
Unvested at July 1, 2009	390,283	$	3.37
Granted	386,914	$	2.91
Vested	(243,954)	$	2.26
Forfeited	(130,084)	$	4.80
Unvested at June 30, 2010	403,159	$	3.15

At June 30, 2010, unrecognized stock compensation expense related to Restricted Stock grants totaled $1,135,229. Such unrecognized expense will be recognized over a weighted average period of 3.0 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, 2010 and 2009 are as follows:

	Year Ended June 30, 2010		Year Ended June 30, 2009
Income taxes paid:	$ 329,800		$ 15,000
Income tax refunds and net operating loss carry-back received:	$ 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:	$ (62,532)		$ (2,043,235)
Oil and natural gas properties incurred through recognition of asset retirement obligations:	$ 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, 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 federal and state income tax returns are open to audit under the statute of limitations for the years ending June 30, 2007 through June 30, 2009.

The components of our income tax benefit are as follows:

	June 30, 2010	June 30, 2009
Current:		

Federal	$	(608,339)	$	(1,993,988)
State		207,952		157,736
Total current income tax benefit		(400,387)		(1,836,252)
Deferred:				
Federal		(553,326)		528,787
State		(218,111)		290,601
Total deferred income tax (benefit) provision		(771,437)		819,388
Total income tax benefit	$	(1,171,824)	$	(1,016,864)

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

		June 30, 2010		**June 30, 2009**
Income tax benefit computed at the statutory federal rate:	$	(1,210,241)	$	(1,230,275)
Reconciling items:				
State income taxes, net of federal tax benefit		(10,413)		148,134
Stock-based compensation (primarily incentive stock options)		105,402		264,060
Deferred tax asset valuation adjustment				(152,588)
Rate adjustment		(42,651)		21,931
Other		(13,921)		(68,126)
Income tax benefit	$	(1,171,824)	$	(1,016,864)

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

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Note 9 Income Taxes (Continued)

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, 2010	June 30, 2009
Deferred tax assets:		
Non qualified stock-based compensation	$ 866,035	$ 657,369
Net operating loss carryforwards	5,389,065	5,389,065
AMT credit carryforward*	645,938	
Other	21,306	22,841
Gross deferred tax assets	6,922,344	6,069,275
Valuation allowance	(5,187,983)	(5,187,983)
Total deferred tax assets	1,734,361	881,292
Deferred tax liability:		
Oil and natural gas properties	(4,684,241)	(4,602,609)
Total deferred tax liability	(4,684,241)	(4,602,609)
Net deferred tax liability	$ (2,949,880)	$ (3,721,317)

* The total AMT credit carryforward is $775,807. Our net deferred tax liability does not include $129,869 of AMT credit carryforward associated with the windfall tax benefit.

We expect to recover approximately $0.7 million in federal income taxes paid during the tax year ended June 30, 2007, as a result of the carry-back of our 2010 income tax loss. Significant intangible drilling costs were incurred during the 2010 fiscal year, of which, we elected to deduct (expense) approximately $1.3 million for federal and state income tax purposes. During the year ended June 30, 2009, we received approximately $2.1 million in federal income taxes paid during the tax years ended June 30, 2007 and 2006, as a result of the carry-back of our 2009 income tax loss. Significant intangible drilling costs were incurred during the 2009 fiscal year, of which, we elected to deduct (expense) approximately $4.8 million for federal and state income tax purposes. Under GAAP, and specifically the full-cost accounting method, intangible drilling costs are capitalized as part of oil and natural gas properties, and depleted using the unit-of-production method. The deduction of intangible drilling costs resulted in a significant difference in the income tax and book basis of our oil and natural gas properties.

At June 30, 2010, we have a federal tax loss carryforward of 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 carryforward that has been disallowed through IRC Section 382.

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.

Eric A. McAfee, a major shareholder of the Company, is also a Managing Director of CMCP.

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.

See also Note 6 for equity transactions with related parties.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 11 Net loss Per Share

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

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

Outstanding potentially dilutive securities as of June 30, 2010 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	$	1.87	159,308
Stock Options and Incentive Warrants	$	1.83	5,482,820
Total	$	1.83	5,642,128

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

Outstanding Potential Dilutive Securities		**Weighted Average Exercise Price**	**Outstanding at June 30, 2008**
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.

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, 2010 under this operating lease are as follows:

For the year ended June 30,		
2011	$	138,089
2012		157,268
2013		159,011
2014		159,011
2015		159,011
Thereafter		172,262
Total	$	944,652

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 12 Commitments and Contingencies (Continued)

Rent expense for the year ended June 30, 2010 and 2009 was $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, 2010 is approximately $499,000.

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

Accounts Receivable. Substantially all of our accounts receivable result from 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 $87,846 and $58,884 for the years ended June 30, 2010 and 2009, respectively.

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Note 15 Subsequent Events

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.

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 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.

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 $85,871 and $502,814, during the years ended June 30, 2010 and 2009, respectively.

	For the Years Ended June 30	
	2010	**2009**
Oil and Natural Gas Activities		
Property acquisition costs:		
Proved property	$ 391,785	$ 876,640

Unproved property		185,154		1,413,941
Exploration costs		2,354,239		349,403
Development costs		890,116		6,486,158
Total costs incurred for oil and natural gas activities	$	3,821,294	$	9,126,142

Estimated Net Quantities of Proved Oil and Natural Gas Reserves (Unaudited)

We adopted revised oil and gas reserve estimation and disclosure requirements as of June 30, 2010. The primary impact of the new disclosures is to conform the definition of proved reserves with the Modernization Requirements, which were issued by the SEC at the end of calendar year 2008. The accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economical to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technology to estimate proved oil and gas reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes. The unaudited supplemental information on oil and gas exploration and production activities for 2010 has been presented in accordance with the new reserve estimation and disclosure rules, which may not be applied retrospectively. The 2008 and 2009 data are presented in accordance with oil and gas disclosure requirements effective during those periods. The effect of applying the new definition of reliable technology and other non-price related aspects of the updated

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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)

rules did not impact 2010 net proved reserve volumes. The effect of applying the 12-month average price, versus the June 30, 2010 year-end price, increased proved reserves by less than 2% of total proved reserves. The standardized measure of discounted future net cash flows as of June 30, 2010 increased by approximately $8.5 million as a result of using the 12-month average price rather than the year-end 2010 price.

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. All of our proved reserves are located in the United States. The following information about our proved oil and natural gas reserves was prepared by independent reserve engineers:

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
June 30, 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
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

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 CO_2 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.

Purchases of minerals in place during 2008 resulted from leasehold acquisitions of proved undeveloped reserves that directly offset currently or historically productive wells in the same fracture trend in the Giddings Field.

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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)

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, 2010 and 2009 are as follows:

	For the Years Ended June 30	
	2010	**2009**
Future cash inflows	$ 827,902,260	$ 127,639,699
Future production costs and severance taxes	(222,826,052)	(36,128,247)
Future development costs	(34,024,112)	(33,317,000)
Future income tax expenses	(213,063,769)	(15,697,532)
Future net cash flows	357,988,327	42,496,920
10% annual discount for estimated timing of cash flows	(196,361,678)	(18,947,129)
Standardized measure of discounted future net cash flows	$ 161,626,649	$ 23,549,791

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices for the year ended June 30, 2010 and period-end commodity prices for the years ended June 30, 2009. The unweighted average of first-day-of-the-month commodity prices over the period July 1, 2009 through June 30, 2010 adjusted by lease for quality, transportation fees, energy content and regional price differentials related to proved reserves of crude oil and natural gas liquids approximated $73.88 and $39.91, respectively, and natural gas approximated $4.10 per MMbtu. At June 30, 2009, the end-of-period prices adjusted by lease for quality, transportation fees, energy content and regional price differentials related to proved reserves of crude oil and natural gas liquids approximated $69.89 and $36.96 per barrel, respectively, and natural gas approximated $3.885 per MMbtu.

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	
	2010	2009
Balance, beginning of year	$ 23,549,791	$ 97,072,641
Net changes in sales prices and production costs related to future production	3,935,863	(144,680,473)
Changes in estimated future development costs	(3,502,403)	24,399,826
Sales of oil and gas produced during the period, net of production costs	(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	236,828,138	
Net change due to revisions in quantity estimates	(934,602)	(20,564,731)
Development costs incurred during the period		5,960,423
Accretion of discount	3,582,622	13,315,725
Net change in discounted income taxes	(91,991,767)	50,903,834
Other	(6,484,171)	(886,315)
Balance, end of year	$ 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, 2010.

This annual report does not include an attestation report of the Company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm pursuant to rules of the Securities and Exchange Commission.

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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, 2010 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 2010 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 2010 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 2010 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 2010 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 2010 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 27, 2010

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

Date		Signature	Title
September 27, 2010	*/s/*	*ROBERT S. HERLIN* *Robert S. Herlin*	*Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)*
September 27, 2010	*/s/*	*STERLING H. MCDONALD* *Sterling H. McDonald*	*Vice President and Chief Financial Officer (Principal Financial Officer)*
September 27, 2010	*/s/*	*GREG S. GOODALE* *Greg S. Goodale*	*Chief Accounting Officer (Principal Accounting Officer)*
September 27, 2010	*/s/*	*EDWARD J. DIPAOLO* *Edward J. DiPaolo*	*Director*
September 27, 2010	*/s/*	*GENE STOEVER* *Gene Stoever*	*Director*
September 27, 2010	*/s/*	*WILLIAM DOZIER* *William Dozier*	*Director*
September 27, 2010	*/s/*	*KELLY W. LOYD* *Kelly W. Loyd*	*Director*
September 27, 2010	*/s/*	*LAIRD Q. CAGAN* *Laird Q. Cagan*	*Director*

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INDEX OF EXHIBITS

MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
2.1	Asset Purchase Agreement for Tullos Field, dated September 3, 2004 (Previously filed as an exhibit to Form 8-K on September 9, 2004)
2.2	Definitive Asset Purchase Agreement, dated as of February 2, 2005, by and between Chadco, Inc., Alan Chadwick McCartney, Sonya McCartney and NGS Sub. Corp. (Previously filed as an exhibit in Form 8-K on February 8, 2005)
2.3	Purchase and Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on May 11, 2006)
2.4	Purchase and Sale Agreement I, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)