Evolution Petroleum Corporation Annual Report 2008

Form 10-K (NYSEMKT:EPM)

Published: September 24th, 2008

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, 2008

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

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)

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes: o No: x

Indicate by check mark whether the registrant (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained in this form, 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer o Smaller reporting company 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, 2007, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $5.05 on the American Stock Exchange was $66,387,795

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 24, was 26,917,234.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
2008 ANNUAL REPORT ON FORM 10-K
TABLE OF CONTENTS

This Form 10-K and the information referenced herein contain forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words "plan," "expect," "project," "estimate," "assume," "believe," "anticipate," "intend," "budget," "forecast," "predict" and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in our 2007 Annual Report on Form 10-KSB for the year ended June 30, 2007 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.

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 prospectus:

"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 1 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 farmout party), to an assignee (the farmin 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 farmout 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 an existing vertical well bore, thereby potentially increasing the area and reach of the well bore that is in contact with the reservoir.

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

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

"MBOE." One thousand barrels of oil equivalent.

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

"MMBTU." One million British thermal units.

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

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

"NGL." Natural gas liquids, being the combination of ethane, propane, butane and natural gasoline's 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." 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 petroleum 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.

"Proved Developed Reserves." Proved Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

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

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

"Proved Reserves." Estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

"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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled.

Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves may not include estimates 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 tests in the area and in the same reservoir.

"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 a present value, discounted at 10% per annum, and is not necessarily the same as market value.

"Royalty" or "Royalty Interest." 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. A royalty interest that is coterminous with an operating or working interest is an "overriding royalty" interest.

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

"Standardized Measure." The standardized measure is an estimate of future net reserves from a property, and is calculated in the same exact fashion as a PV-10 value, except that the projected revenue stream is adjusted to account for the estimated amount of federal income tax that must be paid.

"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.

ITEM 1. BUSINESS

The terms "we," "us," "our," "our Company" and "EPM" refer to Evolution Petroleum Corporation, a Nevada corporation formerly known as Natural Gas 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.

Overview

Our petroleum operations began in September of 2003. We acquire established 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 American Stock Exchange 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, 2008, we had twelve full-time employees, not including contract personnel and outsourced service providers.

Corporate History of Reverse Merger

Reality Interactive, Inc. ("Reality"), a Nevada corporation that traded on the OTC Bulletin Board under the symbol RLYI.OB and the predecessor of NGS, now 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 was 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 our Company, and the crude oil and natural gas business of Old NGS became that of our Company. Concurrently with the listing of our shares on the AMEX during July, 2006, NGS was renamed Evolution Petroleum Corporation to avoid confusion with similar names traded on the 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 us after the merger.

Business Strategy

We are an independent oil and natural gas company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire known oil and natural gas resources and exploit them through the application of conventional and specialized technology to increase production, ultimate recoveries, or both.

We are focused on an overall strategy of acquiring controlling working interests in oil and natural gas resources within established fields and redeveloping those fields through the application of capital and technology to convert a portion of the oil and natural gas resources into profitable producing reserves.

Within this overall strategy, we pursue three specific initiatives:

- Enhanced oil recovery ("EOR"), using miscible and immiscible gas flooding;

II Conventional redevelopment of bypassed primary resources within mature oil and natural gas fields utilizing modern technology and our expertise; and

III Unconventional gas resource development, especially in shale, using modern stimulation and completion technologies.

Our strategy is intended to generate scalable development opportunities at normally pressured depths, exhibiting relatively low completion risk, generally more predictable production lives, less expenditures on infrastructure and lower operational risks. We believe that the benefits of this approach include:

- Reduced exposure to the risk of whether resources are present;
- Reduced capital expenditures per net BOE for infrastructure, such as roads, water handling facilities and pipelines;
- Large inventory of development opportunities, which provides a more predictable future stream of drilling activity and production, as well as potentially reducing risks from short-term oil and natural gas price volatility;
- Reduced operational risks and costs associated with lower pressures and lower temperatures; and
- Control of operations, development timing and technology selection.

Markets and Customers

Historically our crude oil has been produced and sold from properties in the Delhi Field in Louisiana, the Tullos Field Area in Louisiana and the Giddings Field in Texas. All of our natural gas has been produced and sold from our properties in the Delhi Field and the Giddings Field. Since June 2006, we are no longer the operator of the Delhi Field, due to the farmout we completed on June 12, 2006 with Denbury Onshore LLC, a subsidiary of Denbury Resources Inc. ("Denbury") (the "Delhi Farmout"), and, consequently, we have had no natural gas or natural gas liquids production available to us for sales and marketing purposes in the Delhi Field since June 2006. In March 2008 we sold our properties in the Tullos Field Area and as a result have no production or properties from that area. With respect to our properties in the Giddings Field, we have been producing natural gas and natural gas liquids since our first well began production in late February 2008, with two more wells beginning production in mid March, and four wells that began production in May and June of 2008.

Marketing of crude oil and natural gas production 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 20 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 20 years, domestic natural gas prices have been 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 factors tend to influence product prices more for natural gas than for crude oil.

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 Teppco Crude Oil, LLC, a crude oil gathering, transportation, storage and marketing company. Our agreements with both Plains Marketing LP and Teppco Crude Oil, LLC are under a normal (thirty day "evergreen") sales contracts. We believe that other crude oil purchasers are readily available.

Prior to fiscal year 2007, we produced natural gas liquids from our Delhi Field, all of which we sold to Dufour Petroleum, L.P., a subsidiary of Enbridge Energy Partners, LP, at a market competitive price based on an index price of liquid components, less a charge of $0.175 per gallon for transportation and fractionation. Beginning in the second quarter of our 2008 fiscal year we began selling our natural gas and natural gas liquids to DCP Midstream, LP, and ETC Texas Pipeline, LTD., under the terms of normal evergreen sales contracts at competitive prices. We have no other business relationships with our crude oil, natural gas or natural gas liquids purchasers.

Competition

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

Crude oil and natural gas drilling and production operations are regulated by various federal, state and local agencies. These agencies issue binding rules and regulations that carry penalties, often substantial, for failure to comply. These regulations and rules require monthly, semiannual and annual reports on production amounts and water disposal amounts, and govern most aspects of operations, drilling and abandonment, as well as crude oil spills. We anticipate the aggregate burden of federal, state and local regulation will continue and potentially increase. We also believe that our present operations materially comply with applicable regulations. To date, such regulations have not had a material effect on our operations, or the costs thereof, other than as described further in "Item 3. Legal Proceedings". We do not believe that capital expenditures related to environmental control facilities or other regulatory matters will be material in the near term. We cannot predict what subsequent legislation or regulations may be enacted or what effect it will have on our operations or business.

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 and casualty coverage. Not all losses are insured, and we retain certain risks of loss through deductibles, limits and self-retentions. We do not carry lost profits coverage, and our aviation liability insurance coverage is limited to $1million.

ITEM 1A. RISK FACTORS

Risks related to the Company

OPERATING RESULTS FROM OIL AND GAS PRODUCTION MAY DECLINE.

Due to the Delhi Farmout, our future development initiatives in the Delhi Field have been replaced with a CO_2 enhanced oil recovery ("CO_2-EOR") project, in which Denbury has undertaken an obligation to fund, install and operate. We have retained a 25% reversionary interest after a defined payout and separately acquired overriding royalty interests totaling 7.4% in the Delhi CO_2-EOR project. As anticipated, the Delhi Farmout resulted in the reduction of net proved reserves, net production and net revenues accruing to us from the Delhi Field until such time, if at all, as the CO_2-EOR project is completed and brought online.

Concurrent with the sale of our properties in the Tullos Field Area, we began establishing production from newly drilled and completed wells in the Giddings Field. The targeted reservoirs in the Giddings Field typically experience flush production followed by steep harmonic decline rates that steadily flatten to much shallower decline rates. While the newly drilled producing wells in the Giddings Field substantially increased our net production above historic levels, without further development activities in the Giddings Field or our other properties or acquisitions of producing properties, our net production of oil and natural gas will 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 Denbury, requires significant amounts of CO_2 reserves, the source of which may become unavailable or be curtailed. Denbury controls the operations and CO_2 for the project, and as a result, we have a limited ability to control or influence the development and ultimate success of the project. In order to deliver sufficient quantities of CO_2 from Denbury's reserves from its Jackson Dome Field in Mississippi, a pipeline is being constructed to connect to the Delhi Field requiring large amounts of capital resources and the acquisition of permits, right-of-ways, engineering designs, construction personnel and materials. Denbury's failure to manage these and other technical, strategic and logistical risks may render ultimate enhanced recoveries from the planned CO_2-EOR project, if any, to fall short of our expectations in volume and or timing.

The existing well bores we are re-entering in the Giddings Field may have been 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 projects generally require that we acquire new leases in and around established fields 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 proven in the field. Leases may not be available and required oil field services may not be obtainable on the desired schedule or at the expected costs. While the projected drilling results may be considered to be low to moderate in risk, there is no assurance as to what productive results may be obtained, if any.

OUR LIMITED OPERATING HISTORY AND NEWNESS OF OUR 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. All of our current production is the result of recent drilling 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, except for the quarter ended June 30, 2008, in which we recognized positive operating income. 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.

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. Instead, we 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.

REGULATORY AND ACCOUNTING REQUIREMENTS MAY REQUIRE SUBSTANTIAL REDUCTIONS IN REPORTED PROVEN RESERVES (SEE GLOSSARY OF SELECTED PETROLEUM TERMS).

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 carrying value of proved reserves of crude 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 generally requires pricing future revenues at the un-escalated prices in effect as of the end of our fiscal quarter and requires a write down of the carrying value for accounting purposes if the ceiling is exceeded, even if prices declined for only a short period of time. 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 at the end of any fiscal 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 charge to our earnings but would not impact our 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 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 the Delhi Farmout and the sale of our properties in the Tullos Field Area, our near-term future growth and financial condition is highly dependent on our ability to develop 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. 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 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.

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; and
- our access to capital.

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

WE FACE STRONG COMPETITION FROM LARGER CRUDE OIL AND NATURAL 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.

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 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. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices 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.

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. 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.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as Hydraulic Fracturing and Horizontal Drilling do not guarantee that we will find crude oil and/or natural gas in our wells. 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 or Hydraulic Fracturing, 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 and natural gas;
- 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 24% of our reserves at July 1, 2008 are crude oil reserves and 33% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices. While our new projects are evaluated based on the assumption of oil and natural gas prices considerably less than in the current market or projected in the futures market, we do assume commodity prices will be higher than historic levels prior to 2004.

OILFIELD SERVICE AND MATERIALS' PRICES HAVE BEEN ESCALATING, AND THE AVAILABILITY OF SUCH SERVICES MAY BE INADEQUATE TO MEET OUR NEEDS.

Our business plan to redevelop mature 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, the recent escalating costs for such services and materials 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.

Risks Associated with Our Stock

OUR STOCK PRICE HAS BEEN AND MAY CONTINUE TO BE VERY VOLATILE.

Our common stock is thinly traded and the market price has been, and is likely to continue to be, highly volatile. For example, during the year prior to June 30, 2008, our stock price as traded on the American Stock Exchange ranged from $2.15 to $7.17. 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.

The following share calculations treat shares issuable upon the exercise of options or warrants as outstanding (both in the numerator and denominator for percentages) and assume actual vesting.

Our executive officers and directors, in the aggregate, beneficially own approximately 12.4 million shares or approximately 38% of our fully diluted common stock, inclusive of which our Chairman of the Board, Mr. Laird Q. Cagan, Managing Director of Cagan McAfee Capital Partners, LLC ("CMCP") currently owns or controls, directly or indirectly, approximately 7.2 million shares, or approximately 22% of our fully diluted common stock. Mr. Eric McAfee, a Managing Director of CMCP, currently owns or controls, directly or indirectly, approximately 5.0 million shares, or approximately 15% of our fully diluted 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 12.2 million shares, or approximately 37% of our fully diluted common stock. As a result, these holders, if they were to act together, could exercise effective control over all 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.

Table of Contents

THE MARKET FOR OUR COMMON STOCK IS LIMITED AND MAY NOT PROVIDE ADEQUATE LIQUIDITY.

Our common stock is currently thinly traded on the American Stock Exchange. In the year prior to June 30, 2008, the actual trading volume in our common stock ranged from a low of 100 shares of common stock traded to a high of 353,300 shares of common stock traded, with only 66 days exceeding a trading volume of 50,000 shares. On most days, this trading volume means there is limited liquidity in our shares of common stock. Selling our shares is more difficult because smaller quantities of shares are bought and sold and news media coverage about us is limited. These factors result in a limited trading market for our common stock and therefore holders of our stock may be unable to sell shares purchased, should they desire to do so.

IF SECURITIES OR INDUSTRY ANALYSTS DO NOT PUBLISH RESEARCH REPORTS ABOUT OUR BUSINESS OR IF THEY DOWNGRADE OUR STOCK, THE PRICE OF OUR COMMON STOCK COULD DECLINE.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. However, to our knowledge, only four non-company paid 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 AND PREFERRED STOCK WOULD DILUTE EXISTING STOCKHOLDERS.

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

Enhanced Oil Recovery ("EOR") Property

Our EOR Initiative targets the use of miscible and immiscible gas flooding to achieve economic redevelopment and production of tertiary crude oil resources. Field candidates are likely to have already completed primary and secondary recovery operations, generally through water flooding.

Delhi Field

The Delhi Holt Bryant Unit in the Delhi Field in Louisiana, currently our most significant asset, is being redeveloped by Denbury, as operator, through an EOR project utilizing CO_2 technology:

- As of December 31, 2007, Denbury reported to us that approximately $73.0 million of capital has been charged to the project, excluding the $50 million they paid to us in 2006.

- Denbury announced an $80 million capital budget in the Delhi Field for calendar year 2008.

- Denbury anticipates that first CO_2 injection in the Delhi Field should occur in the first half of calendar 2009, with first EOR production from the Delhi Field projected on or about late 2009.

We, and the companies that submitted offers to participate with us, believe that the Delhi Holt Bryant Unit is an excellent candidate for a CO_2-EOR project due to its favorable rock characteristics, large unproven reserves remaining in place, miscibility potential, 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. In June 2006, we conveyed a farmout to Denbury for all of our working interests in the Delhi Holt Bryant Unit and its proved reserves and 75% of our working interests in certain other depths of the Delhi Field, as described in more detail below.

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 W. D. Von Gonten & Co., the third party reservoir engineering firm that prepares our independent estimate of proved reserves, the Delhi Field has produced approximately 200 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 essentially all of the working interests and an 80% net revenue 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 and 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 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.

Concurrent with these activities, we completed internal studies indicating that the reservoirs in the Delhi Holt Bryant Unit, the dominant oil producing reservoirs, were believed to be less than 50% depleted. Based on positive CO_2 pilots conducted by Sun Oil in 1985, and favorable rock characteristics shown in multiple cores taken throughout the Delhi Field, we began discussions in late 2004 with industry partners skilled in tertiary/EOR recovery methods, especially with respect to CO_2 injection.

With positive industry reception, and following extended negotiations with three candidates as prospective partners, we accelerated our redevelopment plan in June 2006 by selling a major portion of our Delhi Field interests, in the form of a farmout, to a subsidiary of Denbury (the "Delhi Farmout"). Important aspects of this transaction include:

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

- Denbury 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 next 6-1/2 years, subject to penalty payments to us for shortfalls in such expenditures. All capital expenditures related to the project are borne by Denbury prior to payout.

- Denbury is the dominant CO_2-EOR operator on the Gulf Coast and currently operates a large number of CO_2-EOR projects and owns naturally occurring 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.

- We retained significant participating interests through separately acquired royalty and overriding royalty interests aggregating 7.4%, and a reversionary working interest equal to 25% of Denbury's working interest (20% revenue interest net to us). We expect the value of these interests will substantially exceed the $50 million cash component of the Delhi Farmout.

- 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 net revenues less direct operating costs in the field reach the threshold.

- We further retained a 25% working interest (20% net revenue interest) in certain other depths outside of the Holt Bryant Unit within the Delhi Field, and believe that additional development potential may exist in the shallower depths.

- We expect to be able to claim proved reserves following the first EOR production response, projected to occur in late calendar 2009 or shortly thereafter.

Conventional Redevelopment Property

Our Conventional Redevelopment Initiative targets the economic development or redevelopment of primary petroleum resources previously bypassed by industry in mature, historically productive formations generally due to inadequate technology or commodity prices.

Giddings Field

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying new Conventional Redevelopment projects. In selecting our candidates:

- We leveraged our staff's extensive experience, gained over many years while employed at UPRC and Anadarko Petroleum Corporation, in the pioneering of horizontal drilling practices adapted to further develop and produce the Austin Chalk and Georgetown formations in the Giddings Field in central Texas;

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

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

We began leasing activities in the Giddings Field in December 2006 and acquired 17,903 net acres as of June 30, 2008. In late 2007, we initiated a redevelopment drilling program in the Giddings Field targeting the Austin Chalk and Georgetown formations. As of June 30, 2008, we have completed that initial drilling program and placed seven wells into production, including five wells that were re-entered, one well that was drilled and one well that was restored to production through a workover.

Essentially all of our proved reserves are located in the Giddings Field and our operations there have increased our total proved reserves by 133% over June 30, 2007, from total proved reserves of 1,723,867 BOE as of July 1, 2007 to 4,018,233 BOE as of July 1, 2008.

Tullos Field Area

On March 3, 2008, we completed the sale of our properties in the Tullos Field Area in LaSalle and Winn Parishes, 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 Area 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. Furthermore, we believe that the potential upside in the Tullos Field Area was substantially less than that offered in our other projects, particularly the Giddings Field drilling program, where the cash proceeds from the sale of our properties in the Tullos Field Area could be expected to yield a much higher return. Last, we had completed the testing of our completion technology utilizing the one well we drilled in the Tullos Field Area and determined that the potential of that technology would be best realized in other fields having less depletion.

Unconventional Natural Gas Resource Property

Our Unconventional Natural Gas Resource Initiative targets the use of modern stimulation and completion technologies for the economic development and production of tight gas formations.

Two Woodford Shale Projects in Oklahoma

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying Unconventional Natural Gas Resource Initiative projects. We chose two projects in the Woodford Shale trend in Oklahoma. In choosing these two projects:

- We are leveraging our staff's expertise in horizontal drilling and tight gas development, a prerequisite to successfully exploiting and developing these resources;

- We are focusing on locations of source rock formations that are well known, especially gas shales;

- We have considered that these projects require large amounts of capital over long periods of time, thereby providing reinvestment opportunities to absorb the substantial cash flows we expect from our future Delhi EOR and Bypassed Resource production; and

- We are adding additional natural gas exposure to balance our existing crude oil exposure.

We began actively acquiring leases in these two projects in May 2007. At June 30, 2008, we had acquired approximately 27,999 and 16,565 gross and net acres, respectively, across the two projects.

Estimated Proved Oil and Natural Gas Reserves and Future Net Revenues

We engaged W. D. Von Gonten & Co. ("Von Gonten") to prepare an independent report of our proved reserves as of July 1, 2008 (the "Reserve Report"). Von Gonten also previously prepared independent reports for all of our proved reserves at July 1, 2007, July 1, 2006, July 1, 2005, July 1, 2004 and January 1, 2004.

Estimates of reserve quantities and values must be viewed as being subject to significant change as more data about the properties becomes available.

Denominated in equivalent barrels using a six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, at July 1, 2008, natural gas represented 43%, natural gas liquids represented 33%, and crude oil represented 24% of total proved reserves, as compared to natural gas of 37% and crude oil of 63% of total proved reserves at July 1, 2007. The increase in proved reserves was due to the leasing, redevelopment and drilling activities in our properties in the Giddings Field, thereby more than offsetting our production and the divestment of proved reserves through our sale of properties in the Tullos Field Area in March 2008. The change in mix of proved reserves is due, in part, to the identification and separation of natural gas liquids in the 2008 report, whereas natural gas liquids were included in the natural gas volumes in the 2007 report.

The following table sets forth, as of July 1, 2008, information regarding our proved reserves based on our Reserve Report. See Note 16 to the consolidated financial statements, where additional reserve information is provided. The average NYMEX prices used to calculate estimated future net revenues were

$138.73 per barrel of crude oil, $84.39 per barrel of natural gas liquid, and $14.00 per MMBTU of natural gas as of June 30, 2008. The NYMEX prices used were adjusted for transportation, market differentials and BTU content of gas produced.

July 1, 2008	Proved Developed Producing	Proved Non-producing	Proved Undeveloped	Total Proved Reserves
Crude Oil (Bbls)	96,167	—	855,874	952,041
NGLs (Bbls)	98,416	11,300	1,200,744	1,310,460
Natural gas (Mcf)	485,701	75,300	9,973,390	10,534,391
Total (BOE)	275,533	23,850	3,718,850	4,018,233
Estimated future net revenues	$ 23,317,256	$ 1,504,919	$ 241,476,331	$ 266,298,506
Estimated future net revenues discounted at 10%	$ 17,423,119	$ 1,372,766	$ 141,457,021	$ 160,252,906

The following table sets forth, as of July 1, 2007, information regarding our proved reserves based on an independent report prepared by Von Gonten. See Note 16 to the consolidated financial statements, where additional reserve information is provided. The average NYMEX prices used to calculate estimated future net revenues were $70.68 per barrel of oil $6.80 per MMBTU of natural gas as of June 30, 2007. The average NYMEX prices used were adjusted for transportation, market differentials and BTU content of gas produced.

July 1, 2007	Proved Developed Producing	Proved Non-producing	Proved Undeveloped	Total Proved Reserves
Crude Oil (Bbls)	324,500	65,200	694,500	1,084,200
Natural gas (Mcf)	—	—	3,838,000	3,838,000
Total (BOE)	324,500	65,200	1,334,167	1,723,867
Estimated future net revenues	$ 9,787,195	$ 1,106,563	$ 39,116,121	$ 50,009,879
Estimated future net revenues discounted at 10%	$ 5,437,733	$ 797,927	$ 27,091,697	$ 33,327,357

Estimated future net revenues discounted at 10% ("PV-10") is a non-GAAP financial measure. 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 of discounted future net cash flows as defined under GAAP.

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

	For the Years Ended June 30	
	2008	2007
Estimated future net revenues	$ 266,298,506	$ 50,009,879
10% annual discount for estimated timing of future cash flows	(106,045,600)	(16,682,522)
Estimated future net revenues discounted at 10%	160,252,906	33,327,357
Estimated future income tax expenses discounted at 10%	(63,180,265)	(11,337,059)
Standardized measure of discounted future net cash flows	$ 97,072,641	$ 21,990,298

During fiscal 2008, we sold production and leaseholds with reserves in place of 51,614 BOE and 433,600 barrels of crude oil, respectively. During fiscal 2007, we sold 28,800 barrels of crude oil.

Sales Volumes, Average Sales Prices and Average Production Costs

The following table set forth certain information regarding sales volumes, average sales prices received for crude oil, natural gas liquids, and natural gas, and expenses for the periods indicated:

	Year Ended June 30, 2008		Year Ended June 30, 2007	
Product	Volume	Price	Volume	Price
Crude oil (Bbls)	29,466	$ 99.03	28,800	$ 64.82
Natural gas liquids (Bbls)	10,639	$ 63.02	—	—
Natural gas (Mcf)	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 $25 and $49 per BOE for the years ended June 30, 2008 and 2007, respectively.

Increased volumes for the year ended June 30, 2008, as compared to the year ended June 30, 2007, were attributable to the development of our properties in the Giddings Field.

Productive Wells and Developed Acreage

Our developed acreage at June 30, 2008 totaled 3,469 net and gross acres, all of which is in the Giddings Field, consisting of a 100% working interest in seven producing wells. Proved undeveloped acreage includes twenty-seven proved drilling locations. Additional drilling locations are associated with our acreage, but require further leasing before being considered for inclusion in our proved reserves.

At June 30, 2007, we owned working interests in 260 net and gross wells consisting of 158 crude oil wells, 23 salt water disposal wells and 93 shut-in wells with uncertain future utility, all located in the Tullos Field Area. Our properties in the Tullos Field Area were sold on March 3, 2008.

Undeveloped Acreage

As of June 30, 2008, we held approximately 57,756 gross and 34,408 net undeveloped acres in the Gulf Coast and Mid-Continent regions of the United States, as follows:

Field	Gross Acreage	Net Acreage
Giddings Field	16,121	14,434
Woodford Shale	27,999	16,565
Delhi Field*	13,636	3,409
Total	57,756	34,408

* 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 scheduled for CO_2-EOR operations within this same acreage, we currently own royalty and overriding royalty interests aggregating approximately 7.4%. Separately, we own a 25% working interest (20% 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.

For more complete information regarding current year activities, including crude oil and natural gas production, refer to “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Corporate Office

Effective on March 1, 2007, we entered into a sublease agreement with Aspen Technology, Inc to rent approximately 8,400 square feet of Class “A” office space in the Westchase District area in West Houston. 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.

ITEM 3. LEGAL PROCEEDINGS.

On August 3, 2007, we were advised of an oil spill in the Tullos Field Area near one of our leases. At the request of field agents of the Louisiana Department of Environmental Quality and the Environmental Protection Agency (“EPA”), we agreed to commence a clean-up operation that was completed by the end of August 2007. A detailed analysis of the oil in the spill compared to the Company’s produced oil was conducted by an EPA approved laboratory. We believe that the oil in the spill did not originate from our operations, supported by the formal findings of the laboratory. We received insurance reimbursements of $484,197 in October 2007 and $217,668 in March 2008. These reimbursements covered all of our actual cleanup costs except a $5,000 insurance deductible and excluding our legal fees, in-house administrative costs, and any possible EPA expense reimbursements and fines that might be billed. On May 5, 2008, we received a letter from the EPA proposing a $5,500 fine related to the oil spill. We have also received a bill from the United States Coast Guard of approximately $70,000 for expense reimbursement. We believe these claims are not supported by independent investigation. As of the date of this filing, we have requested further verification from the United States Coast Guard to support their claims, and have entered into a settlement with the EPA where we have agreed to pay the $5,500 fine with no admission of liability.

In July 2008, a multi-plaintiff lawsuit was filed in the twenty-eighth Judicial District Court, Lasalle Parish, Louisiana, against 15 defendants, including Four Star Development Corporation, a former indirect wholly owned subsidiary of the Company, which was sold on March 3, 2008, as part of our sale of the Tullos Field Area. Plaintiffs claim that the defendants’ oil and natural gas exploration, development and production activities on their properties have caused soil and ground water contamination as a result of the release of hydrocarbons and drilling fluids. Plaintiffs seek damages for testing, clean-up and remediation of the properties as well as diminution in their value and mental anguish and emotional distress to the individual plaintiffs, unjust enrichment and punitive damages for alleged concealment of ongoing activities. At this time, we are not a party to the litigation and are unable at this time to determine the exposure, if any, to the Company.

In November 2005, a multi-plaintiff lawsuit was filed in the Fifth Judicial District Court, Richland Parish, Louisiana, against 18 defendants including NGS Sub Corp. and Arkla Petroleum LLC, the Company’s direct and indirect wholly owned subsidiaries (the “Subsidiaries”), as working interest owners/operators of various oil and natural gas leases in the Delhi Field. Plaintiffs claim that the defendants’ oil and natural gas exploration, development and production activities on their properties have caused soil and ground water contamination as a result of the release of hydrocarbons and drilling fluids. Plaintiffs seek

damages for testing, clean-up and remediation of the properties as well as diminution in their value and mental anguish to the individual plaintiffs, unjust enrichment and punitive damages for alleged concealment of ongoing activities. Defendants have answered plaintiffs’ suit denying plaintiffs’ claims. Trial is set before a jury in Richland Parish for July13, 2009, and we intend to continue contesting plaintiffs’ claims vigorously. Discovery is in process, with Plaintiffs’ expert’s report due to be filed with the Court by September 26, 2008. Defendants have performed field testing which indicates that any contamination is far less pervasive than we believe plaintiffs are claiming, although Plaintiff’s complaints are vague and a full analysis of plaintiffs’ claims cannot be completed until their expert report is available for analysis. While the Delhi Field has been in production for approximately sixty years, NGS Sub Corp. and ARKLA were owner and operator since 2003 and 2002, respectively, until June of 2006. We believe that no contamination of significance has occurred during our ownership of the Delhi Field, and that potential liability for exposure of NGS Sub Corp. results largely through any contractual indemnity of prior working interest owners which NGS Sub Corp. may have assumed for historical operations in the field in its acquisition of the subject oil and gas working interests. At this time, the likelihood or amount of any judgment which might be rendered cannot be determined with any certainty.

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, 2008.

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 American Stock Exchange 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 following table shows, for each quarter of fiscal year 2008 and 2007, the high and low closing sales prices as reported by the American Stock Exchange.

American Stock Exchange

2008:	High	Low
Fourth quarter ended June 30, 2008	$ 7.17	$ 4.16
Third quarter ended March 31, 2008	$ 5.85	$ 3.76
Second quarter ended December 31, 2007	$ 5.60	$ 3.02
First quarter ended September 30, 2007	$ 3.24	$ 2.15
2007:	**High**	**Low**
Fourth quarter ended June 30, 2007	$ 3.66	$ 2.42
Third quarter ended March 31, 2007	$ 3.18	$ 2.49
Second quarter ended December 31, 2006	$ 3.04	$ 2.38
First quarter ended September 30, 2006	$ 3.30	$ 2.64

Holders

As of June 30, 2008, there were 26,870,439 shares of common stock issued and outstanding, held by 155 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	4,446,000(1)	$ 1.87	1,325,859
Equity compensation plans not approved by security holders	1,438,558(2)	$ 1.51	—
Total	5,884,558	$ 1.79	1,325,859

(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, 2008, 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, 2008, there were 3,946,000 shares of common stock issuable upon exercise of outstanding options and 228,141shares of restricted common stock issued directly under the 2004 Stock Plan, leaving 1,325,859 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 services. Total warrants outstanding as of June 30, 2008 related to these services was 401,058 with a weighted average exercise price of $1.40. This also includes 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 a cash bonus, and a warrant to purchase 150,000 shares of common stock in connection with Sterling McDonald's annual performance incentives, including warrants in lieu of a cash bonus.

Recent Sales of Unregistered Securities

In February 2008, we made a direct stock grant for 50,000 shares to Liviakis Financial Communications, Inc. for investor relations services.

In January 2008, we issued 3,099 shares of our common stock upon exercise of warrants totaling 5,000.

In December 2007, we issued 5,207 shares of our common stock upon exercise of warrants totaling 9,463.

The shares issued during the period were exempted from registration in reliance upon Section 4(2) of the Securities Act of 1933, as amended, and Regulation D promulgated thereunder.

ITEM 6. SELECTED FINANCIAL DATA

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

	Year Ended June 30				For the Period from September 23, 2003 (Inception) to June 30, 2004
	2008	2007	2006 (as restated)	2005	
Income Statement Data					
Revenues	$ 4,256,128	$ 1,866,878	$ 2,861,414	$ 1,635,187	$ 142,387
Lease operating expense	$ 1,255,787	$ 1,352,907	$ 1,698,044	$ 853,052	$ 201,116
Production taxes	$ 90,252	$ 62,426	$ 86,562	$ 68,386	$ 17,583
Depreciation, depletion, and amortization	$ 903,214	$ 291,150	$ 407,467	$ 260,124	$ 55,509
Accretion expense	$ 20,196	$ 17,319	$ 27,716	$ 21,824	$ 9,607
General and administrative expense (“G&A”) (excluding stock-based compensation)	$ 3,705,751	$ 2,878,107	$ 2,279,518	$ 1,513,663	$ 992,840
G&A: Stock-based compensation	$ 1,791,486	$ 1,613,493	$ 546,567	$ 707,117	$ 159,014
Gain from sale of oil and natural gas properties	$ —	$ —	$ 45,325,468	$ —	$ —
Income (loss) from operations	$ (3,510,558)	$ (4,348,524)	$ 43,141,008	$ (1,788,979)	$ (1,293,282)
Other income (expense), net	$ 854,130	$ 1,899,460	$ (2,434,867)	$ (375,592)	$ (71,305)
Income tax provision (benefit)	$ (1,085,454)	$ (638,853)	$ 15,007,775	$ —	$ —
Net income (loss)	$ (1,570,974)	$ (1,810,211)	$ 25,698,366	$ (2,164,571)	$ (1,364,587)
Earnings (loss) per common share - Basic	$ (0.06)	$ (0.07)	$ 1.03	$ (0.09)	$ (0.06)
Earnings (loss) per common share - Diluted	$ (0.06)	$ (0.07)	$ 1.01	$ (0.09)	$ (0.06)
Cash Flows Data					
Operating Activities:					
Before changes in operating assets and liabilities	$ 3,707,850	$ (11,865,115)	$ (3,893,417)	$ (1,096,624)	$ (1,109,374)
Changes in operating assets and liabilities	(4,570,886)	(2,626,933)	3,156,213	19,089	8,021
Cash used in operating activities	(863,036)	(14,492,048)	(737,204)	(1,077,535)	(1,101,353)
Investing Activities:					
Development of oil and natural gas properties	(11,187,291)	(417,964)	(2,611,369)	(503,394)	—
Acquisition of oil and natural gas properties	(8,789,501)	(1,918,757)	(1,448,239)	(1,554,149)	(1,499,754)
Proceeds from sale of oil and natural gas properties	4,452,450	155,378	49,993,134	—	—
Cash in qualified intermediary account for “like-kind” exchanges	—	34,662,368	(34,662,368)	—	—
Other	(87,360)	(120,050)	551,467	(721,080)	(309,925)
Cash provided by (used in) investing activities	(15,611,702)	32,360,975	11,822,625	(2,778,623)	(1,809,679)
Financing Activities:					
Payments on notes payable	—	—	(5,634,654)	(1,725,167)	(710,327)
Proceeds from notes payable	—	—	1,003,563	3,526,754	49,490
Equity transactions	76	(15,532)	890,529	4,235,428	3,939,700
Cash provided by (used in) financing activities	76	(15,532)	(3,740,562)	6,037,015	3,278,863
Increase (decrease) in cash and cash equivalents	$ (16,474,662)	$ 17,853,395	$ 7,344,859	$ 2,180,857	$ 367,831

	June 30, 2008	June 30, 2007	June 30, 2006 (as restated)	June 30, 2005	June 30, 2004
Balance Sheet Data					
Total current assets	$ 17,801,070	$ 28,921,518	$ 10,321,359	$ 3,212,558	$ 582,144
Total assets	$ 40,365,848	$ 34,905,992	$ 48,957,958	$ 9,465,224	$ 4,011,065
Total current liabilities	$ 4,171,048	$ 1,596,558	$ 3,476,727	$ 613,326	$ 965,496
Total liabilities	$ 7,362,114	$ 2,122,846	$ 15,962,562	$ 3,953,124	$ 1,276,938
Temporary equity (351,335 shares of common stock outstanding at June 30, 2006)	$ —	$ —	$ 790,500	$ —	$ —
Stockholders’ equity	$ 33,003,734	$ 32,783,146	$ 32,204,896	$ 5,512,100	$ 2,734,127
Common stock outstanding	26,870,439	26,776,234	26,300,670	24,774,606	22,945,406

	Quarter Ended				
	June 30, 2008	March 31, 2008	December 31, 2007	September 30, 2007	June 30, 2007
Revenues					
Crude oil	$ 1,253,478	$ 554,498	$ 607,878	$ 502,273	$ 508,459
Natural gas liquids (“NGLs”)	558,736	90,405	21,293	—	—

Natural gas	544,290	99,799	23,478	—	—
Total operating revenues	2,356,504	744,702	652,649	502,273	508,459
Operating Expense					
Lease operating expense (“LOE”)	284,099	300,186	361,192	310,310	313,680
Production taxes	44,021	12,867	15,808	17,556	18,166
Depreciation, depletion, and amortization (“DD&A”)	530,569	139,086	123,115	110,444	126,357
Accretion expense	3,540	7,110	4,851	4,695	4,545
G&A (excluding stock-based compensation)	954,771	772,555	1,026,115	952,310	1,181,832
G&A: Stock-based compensation	480,043	493,872	441,564	376,007	376,007
Total operating expense	2,297,043	1,725,676	1,972,645	1,771,322	2,020,587
Operating income (loss)	59,461	(980,974)	(1,319,996)	(1,269,049)	(1,512,128)
Interest income, net	81,295	165,014	266,740	341,081	399,343
Net income (loss) before income taxes	$ 140,756	$ (815,960)	$ (1,053,256)	$ (927,968)	$ (1,112,785)
Sales volumes per day					
Oil (Bbls)	105.4	65.0	75.3	76.5	90.2
NGL (Bbls)	95.0	17.6	4.2	—	—
Natural gas (Mcf)	584.0	135.0	39.3	—	—
Total (BOE)	297.7	105.2	86.1	76.5	90.2
Average sales price					
Oil per Bbl	$ 130.71	$ 93.74	$ 87.75	$ 71.41	$ 61.93
NGL per Bbl	64.63	56.29	54.88	—	—
Natural gas per Mcf	10.24	8.12	6.49	—	—
Total per BOE	86.98	77.83	82.43	71.41	61.93
Per BOE					
LOE and production taxes	12.11	32.72	47.61	46.61	40.42
DD&A	19.58	14.54	15.55	15.70	15.39
Accretion expense	0.13	0.74	0.61	0.67	0.55
General and administrative	52.96	132.35	185.36	188.84	189.75
Total operating expense	84.78	180.35	249.13	251.82	246.11
Operating (loss) income	$ 2.20	$ (102.52)	$ (166.70)	$ (180.41)	$ (184.18)
Net income (loss) before income taxes	$ 5.20	$ (85.27)	$ (133.02)	$ (131.93)	$ (135.54)

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. We acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital and technology to increase production, ultimate recoveries, or both.

Our strategy is intended to generate scalable development opportunities at normally pressured depths, exhibiting relatively low completion risk, generally longer and more predictable production lives, less expenditures on infrastructure and lower operational risks.

Within this overall strategy, we pursue three specific initiatives:

I Enhanced oil recovery (“EOR”), using miscible and immiscible gas flooding;

II Conventional redevelopment of bypassed primary resource within mature oil and natural gas fields utilizing modern technology and our expertise; and

III Unconventional gas resource development, using modern stimulation and completion technologies.

Our most significant asset is within our EOR Initiative in the 13,636 acre Delhi Field, located in northeast Louisiana. Our non-operated interests consist of 7.4% in overriding and mineral royalty interests and a 25% after pay-out reversionary working interest in the Delhi Field Holt Bryant Unit, along with a 25% working interest in certain other depths in the Delhi Field resulting from the Delhi Farmout. The Holt Bryant Unit is currently being redeveloped by the operator, Denbury Resources Inc. (“Denbury”), using CO_2 enhanced oil recovery technology and a dedicated portion of Denbury’s proved CO_2 reserves in the Jackson Dome, approximately 100 miles east of Delhi. Injection of CO_2 is expected to begin during the first half of calendar 2009, followed by projected increases in oil production on or about late calendar 2009.

Since our closing of the Delhi Farmout, we have focused on developing projects in our other initiatives, particularly through conventional redevelopment of bypassed resources in the Giddings Field using horizontal drilling methods, and the leasing of unconventional gas shale projects in the Woodford Shale Trend in Oklahoma. Conceptually, our plan going forward can be illustrated as follows:

As indicated by the above chart, (volumes are representative and not to scale), we are funding our current development projects in the Giddings Field and leasing in our gas shale projects with our working capital resources. We expect that net cash flows from our properties in the Giddings Field, our current cash resources and cash flows from the Delhi Project will be used to fund our gas shale projects and other new projects.

Highlights for the year ended June 30, 2008

- **We reported earnings for the quarter ended June 30, 2008**

We reported positive earnings from operations for the quarter ended June 30, 2008 . During the quarter ended June 30, 2008, operating income was $59,461 and net income before income taxes was $140,756. This compares to an operating loss of $1,512,128 and net loss before income taxes of $1,112,785 for the comparable fiscal 2007 period.

- **We substantially increased our proved reserves and high-graded our production and reserve base, redeploying assets from the Tullos Field Area to the Giddings Field, within our Bypassed Resource Initiative**

Proved reserves increased 133% from 1.72 MMBOE to 4.02 MMBOE, despite production, adjustments and sales of minerals in place totaling approximately 0.68 MMBOE. Through leasing and development activities in the Giddings Field during fiscal 2008, we added 2.97 MMBOE to the 1.72 MMBOE of proved reserves we owned at July 1, 2007. Additions were offset by 0.68 MMBOE of reductions, consisting of 52 MBOE of production, 193 MBOE of downward revisions and 433 MBOE of divested proved reserves from our properties in the Tullos Field Area. Proved locations in the Giddings Field increased from 12 locations at the beginning of the year, to 27 locations and seven production wells (34 wells and locations) at July 1, 2008. Proved developed reserves began the year at 389 MBOE, all located at our now divested properties in the Tullos Field Area, and ended the year at 299 MBOE, all located in the Giddings Field.

Sales volumes increased 230% & 79% during the three and twelve months ended June 30, 2008 vs. 2007, respectively.   Gains were solely attributable to our new production in the Giddings Field, with primary production beginning almost simultaneously with the March 3, 2008 sale of our historical production base in the Tullos Field Area. Our first well in the Giddings Field began production in late February, two more wells began production in mid March, and four wells began production in May and June. Despite the delay in obtaining full productive rates in several of our first wells in the Giddings Field due to drilling fluid production, June averaged 468 net BOEPD of production (approximately 580 gross BOEPD).

We lowered per barrel lifting costs by 74%, or 34.50 per BOE, during our most recent fiscal quarter, while depletion increased less than $4 per BOE. Lifting costs were $12.11 per BOE during the quarter ended June 30, 2008, our first quarter that included only production from our properties in the Giddings Field. During the quarter ended September 30, 2007, the last quarter that included only production from our properties in the Tullos Field Area, lifting costs averaged $46.61 per BO. Due to additions of reserves at the Giddings field during the period, which are higher than our historical acquisition costs of our properties in the Tullos Field Area, our depletion rate rose from $15.70 to $19.58 per BOE.

The forgoing was a result of redeploying our working capital and the proceeds from the sale of our properties in the Tullos Field Area into acquisitions and drilling at our properties in the Giddings Field. On March 3, 2008, we completed the sale of our properties in the Tullos Field Area for gross cash proceeds of approximately $4.6 million. While only producing about 100 gross and 79 net barrels of oil production per day from over 150 producing wells, these properties 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. Furthermore, we believed the potential upside in the Tullos Field Area was substantially less than our other projects, particularly as compared to our properties in the Giddings Field. We also completed the testing of our completion technology utilizing the one well we drilled in the Tullos Field Area and determined that the potential of that technology would be best realized in other, less depleted fields.

In late 2006 we bean leasing in the Giddings Field, and in late calendar 2007 we initiated a redevelopment drilling program targeting the Austin Chalk formation. Initially composed of ten re-entries, we subsequently revised the program to six wells with an aggregate horizontal footage exceeding the initial ten well program. This drilling was completed by fiscal year end, albeit at a higher capital cost than originally expected due to higher well service and materials' costs, unexpected downhole problems in the wells being re-entered, overall learning curve costs associated with starting a new program and higher loss of drilling fluid than expected. As of June 30, 2008, seven wells have been placed in production, including five wells that were re-entered for additional drilling and recompletion, one new well that was drilled and completed, and one well that was restored to production.

To date, results of the drilling program are consistent with our expectations and we continue to move forward in our program of converting existing proved undeveloped locations to producing well status.

- **Our Delhi EOR-CO_2 project continued to progress**

Denbury charged $73.0 million of capital to Delhi during calendar 2007, and announced an $80 million budget for 2008.   We understand that the Mississippi River crossing permits have been obtained by the Corps of Engineers, and that the final leg of the CO_2 supply pipeline and field preparations were actively being constructed. Denbury, the operator of the Delhi Holt Bryant Unit, reported to us that, as of December 31, 2007, approximately $73.0

million of capital has been charged to the Delhi Project, excluding the $50 million they paid to us in 2006. Denbury, disclosed a capital expenditure budget of $80 million for calendar year 2008 for the completion of the CO_2 supply pipeline to Delhi and related field activities. Although we don't control the operations, we expect that oil production response will occur within six months of first injection and that the field oil production rate will steadily increase from that point. We have no expected capital expenditure requirements related to the ongoing CO_2-EOR development at the Delhi Field, although we retain our separate 7.4% overriding and mineral royalty interests and 25% reversionary interest after payout.

· **We continued to advance our Unconventional Gas shale projects**

We substantially increased our net acreage in our two Woodford Shale projects in Oklahoma. At June 30, 2008, we owned approximately 27,999 gross and 16,565 net acres in these projects, as compared to 2,290 gross and 1,145 net acres at June 30, 2007. Offset operators have announced the drilling and completion of numerous wells in the immediate areas.

· **We remained financially strong**

We protected our short-term investments during difficult credit market conditions. We maintained our cash liquidity by continuing to avoid structurally enhanced investment securities, auction rate securities and other questionable credit instruments. Instead, we relied upon lower yielding U.S. Government Agency money market funds during fiscal 2008. In July 2008, we moved our investments into U.S. Treasury money market funds to avoid Agency exposure.

We remained debt free.

· **Looking forward in Fiscal 2009**

We expect to increase development drilling expenditures by 21%, and decrease land expenditures by 65%. We currently expect capital expenditures of $19 million during fiscal 2009, of which approximately $16 million will be dedicated to development drilling and the balance to leasehold acquisitions. This compares to approximately $13.2 million of development drilling expenditures and approximately $8.6 million of land acquisition expenditures during fiscal 2008. Drilling expenditures of approximately $15.0 million will be focused on our properties in the Giddings Field, with additional expenditures for initial test drilling in our Woodford Shale projects. Although at a lesser pace, we will continue to acquire additional proved locations in the Giddings Field.

We expect to begin a new project within our Bypassed Resource Initiative. Our capital budget includes the acquisition of leases within a new project and application of the technology we tested at the Tullos Field Area. Expenditures for this project are scheduled for late fiscal 2009 on a mature field in Texas.

We expect first injection of CO2 at Delhi in the first half of calendar 2009. Based on the operator's current plans, Denbury should be injecting CO2 at Delhi in the first half of calendar 2009, with expected oil production accruing to us from our 7.4% overriding and royalty interests on or about late calendar 2009.

We expect to preserve our financial strength. We recognize that the world and U.S. economies are experiencing unprecedented credit market stress and volatility, which makes us even more determined to live within our means. Consequently, we may reduce capital expenditures from our budget based on a number of factors, including changes in the commodity prices that we expect to receive, drilling and production performance results from new and existing wells, unexpected changes in our working capital, insufficient joint venture capital, or such other factors as we deem appropriate. We believe any retrenchment would be brief, only serving as a bridge to reach our expected annuity from Delhi production, which appears to be around the corner for the benefit of our shareholders.

Liquidity and Capital Resources

At June 30, 2008, our working capital, predominately cash and cash equivalents, was approximately $13.6 million and we continued to be debt free. This compares to working capital of approximately $27.3 million at June 30, 2007. Of the $13.7 million decrease in working capital since June 2007, approximately $20.0 million was used for capital expenditures on oil and natural gas leasehold and development costs, approximately $0.1 million was used for capital expenditures on other property and equipment, and approximately $0.9 million was used in operations, offset by net proceeds from the sale of our properties in the Tullos Field Area of approximately $4.5 million and an increase of approximately $2.8 million in net operating assets.

For the year ended June 30, 2008, approximately $0.9 million was used in operations. This compares to approximately $14.5 million used in operations for the year ended June 30, 2007, which included approximately $14.6 million paid for income taxes.

Cash flows used in investing activities totaled approximately $15.6 million during the year ended June 30, 2008. This compared to approximately $32.4 million provided by investing activities for the year ended June 30, 2007. During the current fiscal period approximately $20.0 million of cash was used for investments to acquire and develop oil and natural gas property interests, which does not include approximately $1.6 million net change in accounts payable from July 1, 2007 relating to expenditures for oil and natural gas properties, and approximately $0.2 million of asset retirement costs. We also acquired approximately $0.1 million in other property and equipment. The sale of our properties in the Tullos Field Area partially offset our acquisition and development activities by providing net proceeds of approximately $4.5 million.

During the year ended June 30, 2007, we received $34.7 million from the qualified intermediary account representing unspent 1031 "like-kind" exchange funds from the Delhi Farmout, partially offset by approximately $2.3 million of cash used for investments to acquire and develop oil and natural gas property interests and other property and equipment.

There were no significant cash flows from financing activities during the years ended June 30, 2008 and 2007.

We incurred approximately $21.8 million in capital expenditures for oil and natural gas leasehold and development costs during the year ended June 30, 2008 compared to approximately $2.3 million during the year ended June 30, 2007, including approximately $8.6 million for leasehold acquisitions and approximately $13.2 million for development activities. We expect our capital expenditures for oil and natural gas leasehold and development costs to continue during the 2009 fiscal year related to diminished incremental leasing in the Giddings Field and in our gas shale projects in Oklahoma. Based on our current plans, we expect capital expenditures to approximate $19 million during fiscal 2009, with approximately $16 million dedicated to development drilling and the balance to leasehold acquisitions. We expect to fund our development drilling and acquisition activities for fiscal year 2009 primarily from current working capital and cash provided by our operations in the Giddings Field, supplemented by up to $5.0 million from joint ventures.

Results of Operations

Year ended June 30, 2008 compared with the year ended June 30, 2007

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

	Year Ended June 30 2008	Year Ended June 30 2007	Variance	% change
Production Volumes, net to the Company:				
Crude oil and natural gas liquids (Bbl)	30,810	29,148	1,662	6%
Natural gas liquids ("NGLs") (Bbl)	10,639	—	10,639	—
Natural gas (Mcf)	69,051	—	69,051	—
Crude oil, NGLs and natural gas (BOE)	52,958	29,148	23,810	82%
Sales Volumes, net to the Company:				
Crude oil (Bbl)	29,466	28,800	666	2%
NGLs (Bbl)	10,639	—	10,639	—
Natural gas (Mcf)	69,051	—	69,051	—
Crude oil, NGLs and natural gas (BOE)	51,614	28,800	22,814	79%
Revenue data (a):				
Crude oil	$ 2,918,127	$ 1,866,878	$ 1,051,249	56%
NGLs	670,434	—	670,434	—
Natural gas	667,567	—	667,567	—
Total revenues	$ 4,256,128	$ 1,866,878	$ 2,389,250	128%
Average prices (a):				
Crude oil (per Bbl)	$ 99.03	$ 64.82	$ 34.21	53%
NGLs (per Bbl)	63.02	—	—	—
Natural gas (per Mcf)	9.67	—	—	—
Crude oil, NGLs and natural gas (per BOE)	$ 82.46	$ 64.82	$ 17.64	27%
Expenses (per BOE)				
Lease operating expenses and production taxes (b)	$ 25.39	$ 49.14	$ (23.75)	(48)%
Depletion expense on oil and natural gas properties (c)	$ 16.44	$ 9.68	$ 6.76	70%

(a) Includes the cash settlement of hedging contracts in 2007.
(b) Excludes non-recurring oil spill expenses in the current period of $35,417.
(c) Excludes depreciation of furniture and fixtures of $54,668 and $12,335 for the year ended June 30, 2008 and 2007, respectively.

Net Loss. For the year ended June 30, 2008, we reported a net loss of $1,570,974, or $0.06 loss per share (which includes approximately $2.7 million of non-cash charges related to stock based compensation, depreciation, depletion, and amortization, and accretion on asset retirement obligations) on total oil and natural gas revenues of $4,256,128, as compared to a net loss of $1,810,211, or $0.07 loss per share (which includes approximately $1.9 million of non-cash charges related to stock based compensation, depreciation, depletion, and amortization, and accretion on asset retirement obligations) on total oil and natural gas revenues of $1,866,878 for the year ended June 30, 2007. The decrease in our net loss is primarily attributable to increases in revenues of $2,389,250 and an increase in our income tax benefit of $446,601, partially offset by an increase in depreciation, depletion and amortization of $612,064, an increase in general and administrative expenses of $1,005,637 and a decrease in interest income earned of $1,066,465. Additional details of the components of net loss are explained in greater detail below.

Sales Volumes. Crude oil, natural gas liquids, and natural gas sales volumes, net to our interest, for the year ended June 30, 2008 increased 79% to 51,614 BOE, compared to 28,800 BOE for the year ended June 30, 2007. The increase in sales volumes is due primarily to new production of crude oil, NGLs and natural gas from our properties in the Giddings Field. Of the 51,614 BOE sold during the year ended June 30, 2008, the Tullos Field Area, which was sold on March 3, 2008, accounted for approximately 17,995 BOE or approximately 35% of total sales volumes. For the year ended June 30, 2007, the Tullos Field Area accounted for 28,507 BOE or approximately 99% of total sales volumes.

Our first well in the Giddings Field began production in late February 2008, two more wells began production in mid March, and four wells began production in May and June, with June average net sales volumes of 212 Bbls/D of crude oil, 137 Bbls/D of NGLs and 630 Mcf/D or a total of 454 net BOEPD. In contrast, average daily net sales volumes from our properties in the Tullos Field Area in February 2008, our last full month of production prior to its sale on March 3, 2008, was 66 Bbls/D. During our ownership, we had no NGL or natural gas production from our properties in the Tullos Field Area.

Production. Oil production will vary from oil sales volumes by changes in crude oil inventories, which are not carried on our balance sheet. Crude oil, NGL and natural gas production for the year ended June 30, 2008 increased 82% to 52,958 BOE, compared to 29,148 BOE for the year ended June 30, 2007. The increase is primarily due to oil, NGL and natural gas production from our properties in the Giddings Field. Production from the Tullos Field Area, which was sold on March 3, 2008, accounted for approximately 36% of production for the year ended June 30, 2008 compared to approximately 98% for the year ended June 30, 2007.

Oil, NGL and Natural Gas Revenues. Revenues presented in the table above and discussed herein represent revenue from sales of our oil and natural gas production volumes, net to our interest. In the previous year, production sold under fixed price delivery contracts, which have been designated for the normal purchase and sale exemption under Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*, are also included in these amounts. Realized prices may differ from market prices in effect during the periods, depending on when the fixed delivery contract was executed.

Crude oil, NGL and natural gas revenues for the year ended June 30, 2008 increased 128% from the previous fiscal year. This was due to a 53% increase in the price of a Bbl of oil, from $65 per Bbl to $99 per Bbl, along with sales of NGLs and natural gas during the year ended June 30, 2008, whereas there were no sales of NGLs and natural gas during the year ended June 30, 2007. Oil revenues from our properties in the Tullos Field Area, which was sold in March 2008, were $1,477,355, or approximately 35% of total revenues, for the year ended June 30, 2008, compared to $1,828,245, or approximately 98% of total revenues, for the year ended June 30, 2007.

Lease Operating Expenses (including production severance taxes). Lease operating expenses for the year ended June 30, 2008 decreased approximately 5% from the comparable 2007 period. The overall decrease in lease operating expenses in 2008 is primarily attributable to lower field expenses in the Giddings Field as compared to the Tullos Field Area and the inclusion of only eight months of field expense due to the sale of our properties in the Tullos Field Area in early March 2008. On a BOE basis, lease operating expenses decreased by 48% over the comparable 2007 period, due to lower lease operating costs and higher sales volumes.

General and Administrative Expenses ("G&A"). G&A expenses increased 22% to approximately $5.5 million for the year ended June 30, 2008, compared to approximately $4.5 million for the year ended June 30, 2007. Higher overall compensation expenses for estimated bonuses and new hires accounted for the majority of the increase. New hires are associated with a build up of our infrastructure to execute our drilling program in the Giddings Field. Non-cash stock-based compensation expense was $1,791,486 and $1,613,493 for the years ended June 30, 2008 and 2007, respectively.

Depreciation, Depletion & Amortization Expense ("DD&A"). DD&A expense increased $612,064 to $903,214 for the year ended June 30, 2008 from $291,150 for the year ended June 30, 2007. The increase is primarily due to a higher depletion rate ($16 vs. $10) per BOE and a 79% increase in sales volumes. The increase in the depletion rate is due to the higher development cost of PUDs in the Giddings Field that we added in replacement of our lower cost PDP's from our properties in the Tullos Field Area, which we sold in March 2008.

Interest Income. Interest income for the year ended June 30, 2008 decreased $1,066,465 to $854,448, compared to $1,920,913 for the year ended June 30, 2007. The decrease in interest income is due to lower available cash balances averaging approximately $19.5 million during the year ended June 30, 2008, as compared to cash balances averaging approximately $36.2 million during the year ended June 30, 2007, combined with a lower interest rate environment during the year ended June 30, 2008. The lower cash balance is mostly due to cash used to pay income taxes arising from the $50 million we received from the Delhi Farmout and for additions to our oil and natural gas properties.

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 high price increases for oilfield equipment, tubulars, labor and services for the years ended June 30, 2008 and 2007. Similarly, the prices we received for our products during this period has also increased dramatically, thereby offsetting material impacts on our results of operations.

Seasonality. Our business is generally not seasonal, except for certain rare instances when weather conditions may adversely affect access to our properties. Although we do not generally modify our production for changes in market demand, we do experience seasonality in the product prices we receive, generally based on higher demand for natural gas in the summer and winter and higher demand for downstream oil products during the summer driving season.

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 method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and natural gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full-cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and natural gas properties, the successful efforts method follows the guidance of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, under which the net book value of assets are measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost method, the full-cost pool (net book value of oil and natural gas properties) is measured against future net cash flows discounted at 10% using commodity prices in effect at the end of the reporting period. The financial results for a given period could be substantially different depending on the method of accounting that a company adopts.

Oil and Natural Gas Reserves, Depletion, and the Ceiling Test. Under full-cost accounting, the estimated quantities of proved oil and natural gas reserves and the related present value of estimated future net cash flows used to calculate depletion and to perform the full-cost ceiling test have a significant impact on the underlying financial statements. 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 the report, 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 full-cost ceiling test calculation and could significantly affect our DD&A rate. A 10% decrease in commodity prices as of June 30, 2008, would not result in an impairment of our oil and natural gas properties. A 10% increase in our estimate of proved reserves quantities would have lowered our fourth quarter 2008 DD&A rate from $19.58 per BOE to $17.70 per BOE, and a 10% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $21.53 per BOE.

Unproved Properties. On a quarterly basis, the costs of unproved properties are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairment. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Impairments and abandonments of unproved properties are accounted for as an adjustment to capitalized costs related to proved oil and natural gas properties, with no losses recognized.

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, 2008, 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 rates 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. An increase of 10% in our current estimated volatility from the current volatility of 89% to 99% would increase the fair value of future grants of stock options approximately 6%. Conversely, a decrease of 10% in our current estimated volatility would decrease the fair value of future grants of stock options approximately 7%.

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements at June 30, 2008.

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 revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. 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. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Although our current production base may not be sufficient enough to effectively allow hedging, we may periodically use derivative instruments to hedge our commodity price risk. We may hedge a portion of our projected oil and natural gas production through a variety of financial and physical arrangements intended to support oil and natural gas prices at targeted levels and to manage our exposure to price fluctuations. We may use futures contracts, swaps and fixed price physical contracts to hedge our commodity prices. Realized gains and losses from our price risk management activities are recognized in oil and natural gas sales when the associated production occurs. We do not hold or issue derivative instruments for speculative purposes.

ITEM 8. FINANCIAL STATEMENTS

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The 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, 2008 and 2007 and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended June 30, 2008 and 2007. 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. The Company has determined that it is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. 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 and subsidiaries as of June 30, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board ("FASB") Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109, Accounting for Income Taxes* , during the year ended June 30, 2008.

HEIN & ASSOCIATES LLP

Houston, Texas
September 22, 2008

Evolution Petroleum Corporation and Subsidiaries
Consolidated Balance Sheets

	June 30, 2008	June 30, 2007
Assets		
Current Assets		
Cash and cash equivalents	$ 11,272,280	$ 27,746,942
Receivables		
Oil and natural gas sales	2,066,300	190,210
Income tax	478,599	421,325
Other	86,966	22,375
Income taxes recoverable	3,625,987	—
Prepaid expenses and other current assets	270,938	540,666
Total current assets	17,801,070	28,921,518
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties – full cost method of accounting	22,047,233	5,459,553
Other property and equipment	161,027	154,872
Total property and equipment	22,208,260	5,614,425
Other assets, net	356,518	370,049
Total assets	$ 40,365,848	$ 34,905,992
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 2,892,459	$ 1,064,918
Accrued expenses	805,262	524,809
Royalties payable	473,327	6,831
Total current liabilities	4,171,048	1,596,558

Long term liabilities		
Deferred income taxes	2,901,929	338,001
Deferred rent	74,081	47,289
Asset retirement obligations	215,056	140,998
Total liabilities	7,362,114	2,122,846
Commitments and contingencies (Note 13)		
Stockholders' equity		
Common Stock; par value $0.001; 100,000,000 shares authorized; 26,870,439 and 26,776,234 issued and outstanding as of June 30, 2008 and June 30, 2007, respectively.	26,870	26,776
Additional paid-in capital	14,188,841	12,397,373
Retained earnings	18,788,023	20,358,997
Total stockholders' equity	33,003,734	32,783,146
Total liabilities and stockholders' equity	$ 40,365,848	$ 34,905,992

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Operations

	Year Ended June 30,	
	2008	2007
Revenues		
Crude oil	$ 2,918,127	$ 1,866,892
Natural gas liquids	670,434	—
Natural gas	667,567	—
Price risk management activities	—	(14)
Total revenues	4,256,128	1,866,878
Operating Costs		
Lease operating expense	1,255,787	1,352,907
Production taxes	90,252	62,426
Depreciation, depletion and amortization	903,214	291,150
Accretion of asset retirement obligation	20,196	17,319
General and administrative *	5,497,237	4,491,600
Total operating costs	7,766,686	6,215,402
Loss from operations	(3,510,558)	(4,348,524)
Other income (expense)		
Interest income	854,448	1,920,913
Other	(318)	(21,453)
Net loss before income tax benefit	(2,656,428)	(2,449,064)
Income tax benefit	(1,085,454)	(638,853)
Net loss	$ (1,570,974)	$ (1,810,211)
Loss per common share		
Basic and Diluted	$ (0.06)	$ (0.07)
Weighted average number of common shares		
Basic and Diluted	26,786,270	26,706,713

*General and administrative expenses for year ended June 30, 2008 and 2007 included non cash stock-based compensation expense of $1,791,486 and $1,613,493, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Cash Flow

	Year Ended June 30,	
	2008	2007

		2008		2007
Cash flows from operating activities				
Net loss	$	(1,570,974)	$	(1,810,211)
Adjustments to reconcile net loss to net cash used in operating activities				
Depreciation, depletion and amortization		903,214		291,150
Stock-based compensation		1,791,486		1,613,493
Accretion of asset retirement obligations		20,196		17,319
Deferred income taxes		2,563,928		(12,024,155)
Deferred rent		26,792		47,289
Changes in operating assets and liabilities:				
Receivables		(5,623,942)		(501,539)
Prepaid expenses and other current assets		90,902		(245,225)
Accounts payable and accrued expenses		468,866		805,673
Royalties payable		466,496		(40,223)
Income tax payable		—		(2,645,619)
Net cash used in operating activities		(863,036)		(14,492,048)
Cash flows from investing activities				
Net proceeds from the sale of the Tullos Assets		4,420,868		—
Proceeds from other asset divestitures		31,582		155,378
Development of oil and natural gas properties		(11,187,291)		(417,964)
Acquisitions of oil and natural gas properties		(8,789,501)		(1,918,757)
Capital expenditures for other equipment		(87,544)		(156,644)
Cash in qualified intermediary account for “like-kind” exchanges		—		34,662,368
Other assets		184		36,594
Net cash (used in) provided by investing activities		(15,611,702)		32,360,975
Cash flows from financing activities				
Equity transaction costs		—		(15,657)
Proceeds from issuance of common stock		76		125
Net cash provided by (used in) financing activities		76		(15,532)
Net (decrease) increase in cash and cash equivalents		(16,474,662)		17,853,395
Cash and cash equivalents, beginning of period		27,746,942		9,893,547
Cash and cash equivalents, end of period	$	11,272,280	$	27,746,942
Supplemental disclosure of cash flow information:				
Income taxes paid	$	33,879	$	14,560,000
Non-cash transactions:				
Increase in accounts payable incurred to acquire oil and natural gas leasehold interests and develop oil and natural gas properties.	$	1,639,128	$	—

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Changes in Stockholders’ Equity
For the Years ended June 30, 2008 and 2007

	Common Stock Shares		Common Stock Par Value		Additional Paid-in Capital		Retained Earnings		Total Stockholders’ Equity
Balance, June 30, 2006	26,300,670	$	26,300	$	10,009,388	$	22,169,208	$	32,204,896
Issuance of restricted common stock	107,242		108		—		—		108
Exercise of warrants	16,987		17		—		—		17
Reclassify temporary equity	351,335		351		790,149		—		790,500
Stock issuance costs	—		—		(15,657)		—		(15,657)
Stock based compensation	—		—		1,613,493		—		1,613,493
Net loss	—		—		—		(1,810,211)		(1,810,211)
Balance, June 30, 2007	26,776,234	$	26,776	$	12,397,373	$	20,358,997	$	32,783,146
Issuance of restricted common stock	75,899		76		—		—		76
Exercise of warrants	8,306		8		(8)		—		—
Exercise of stock options	10,000		10		(10)		—		—
Stock based compensation	—		—		1,791,486		—		1,791,486
Net loss	—		—		—		(1,570,974)		(1,570,974)
Balance, June 30, 2008	26,870,439	$	26,870	$	14,188,841	$	18,788,023	$	33,003,734

See accompanying notes to consolidated financial statements.

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, formerly Natural Gas Systems, Inc. (the "Company", "we" or "us"), is an independent petroleum 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. 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 believed 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. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2008 and 2007, no allowance for doubtful accounts was 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. Oil and natural gas property costs excluded represent investments in unproved 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.

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required to periodically perform a "ceiling test" which determines a limit on the book value of our oil and natural gas properties. If the net capitalized cost of proved oil and natural gas properties, net of related deferred income taxes, plus the cost of unproved oil and natural gas properties, exceeds the present value of estimated future net cash flows discounted at 10 percent, net of related tax effects,

Note 2 – Summary of Significant Accounting Policies (Continued)

plus the cost of unproved oil and gas properties, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization ("DD&A"). Future net cash flows are based on period-end commodity prices and exclude future cash outflows related to estimated abandonment costs. We did not have a ceiling test impairment during the years ended June 30, 2008 and 2007.

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. Our investment in oil and natural gas properties includes an estimate of the future cost associated with dismantlement, abandonment and restoration of our properties. These costs are recorded as provided in Statement of Financial Accounting Standards ("SFAS") No. 143, Accounting *for Asset Retirement Obligations* . The present value of the future costs (the "asset retirement cost") is added to the capitalized cost of our oil and natural gas properties and recorded as a long-term or current liability. The asset retirement cost is depleted over the life of our oil and natural gas properties. The estimation of future costs associated with dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

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

Stock-based Compensation. Effective July 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment* ("SFAS No. 123(R)"), using the modified prospective transition method which requires, among other things, current recognition of compensation expense for share-based compensation granted after July 1, 2006, and for that portion of prior period share-based compensation for which the requisite service had not been rendered as of July 1, 2006. SFAS No. 123(R) requires that 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 awards and recognize compensation cost on a straight-line basis over our awards' vesting periods.

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 account for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109") and, as of July 1, 2007, the Financial Accounting Standards Board ("FASB") Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). 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.

Note 2 – Summary of Significant Accounting Policies (Continued)

FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We recognize estimated interest and penalties related to any potential underpayment on unrecognized tax benefits as a component of income tax expense in the Consolidated Statement of Operations.

Earnings (loss) per share. Earnings (loss) per share ("EPS") of common Stock is computed in accordance with SFAS No. 128 *Earnings per Share* ("SFAS No. 128"). Under the provisions of SFAS No. 128, basic 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 antidilutive. Including potential dilutive common shares in the denominator of a diluted EPS computation for continuing operations always will result in an antidilutive 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. The following discloses the existence and effect of accounting standards issued but not yet adopted by us with respect to accounting standards that may have an impact on the Company when adopted in the future.

Accounting for Business Combinations. In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* ("SFAS No. 141R"), which replaces SFAS No. 141, *Business Combinations*. SFAS No. 141R establishes principles and requirements for determining how an enterprise recognizes and measures the fair value of certain assets and liabilities acquired in a business combination, including non-controlling interests, contingent consideration, and certain acquired contingencies. SFAS No. 141R also requires acquisition-related transaction expenses and restructuring costs be expensed as incurred rather than capitalized as a component of the business combination. SFAS No. 141R will be applicable prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R would have an impact on accounting for any businesses acquired after the effective date of this pronouncement.

Accounting for Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The provisions of SFAS No. 157 will be applied prospectively as of the beginning of the fiscal year in which it is initially applied except for, among other items, a financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in footnote 3 of Issue 02-3 prior to initial application of SFAS No. 157. In February 2008, the FASB deferred the effective date of SFAS No. 157 by one year for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a financial statements on a nonrecurring basis and amended SFAS No. 157 to exclude SFAS No. 13, *Accounting for Leases,* and its related interpretive accounting pronouncements that address leasing transactions. SFAS No. 157 did not have an impact on our financial statements when adopted on July 1, 2008. We are currently evaluating what the impact, if any, of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities will have on our financial statements.

Note 3 – Recent Accounting Pronouncements (Continued)

Accounting for the Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* ("SFAS No. 159"), which permits all entities to choose, at specified election dates, to measure eligible items at fair value. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, and thereby mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. The Statement did not have an impact on our financial statements when adopted on July 1, 2008.

Note 4 – Sale of Oil and Natural Gas Properties

On March 3, 2008, NGS Sub Corp., a Delaware corporation a wholly owned by EPM ("NGS Sub"), pursuant to an Asset Purchase and Sale Agreement (the "Asset Sale Agreement") dated February 15, 2008, completed the sale of its 100% working interest and approximately 79% average net revenue interest in producing and shut-in crude oil wells, water disposal wells, equipment and improvements located in the Tullos Urania, Colgrade and Crossroads Fields in LaSalle and Winn Parishes, Louisiana (the "Tullos Field Area"). The following table presents the transaction and its affect on our financial statements.

Proceeds from sale of properties in the Tullos Field Area	$	4,649,241
Less payout of a third party carried interest arrangement		(168,106)
Less miscellaneous transaction costs		(60,267)
Net proceeds		4,420,868
Net book value of our properties in the Tullos Field Area on March 3, 2008		
Asset retirement obligation		153,886
Oil and natural gas properties		(1,721,990)
Other property and equipment		(26,721)
Prepaid expenses and other current assets		(178,826)
Other assets		(13,347)
Remaining credit recorded to oil and natural gas properties	$	2,633,870

The following unaudited pro forma consolidated financial information is presented for illustrative purposes only and presents the pro forma operating results for the Company for the year ended June 30, 2008 and 2007 as though the disposition of our properties in the Tullos Field Area occurred at the beginning of the period. The unaudited pro forma consolidated financial information is not intended to be indicative of the operating results that actually would have occurred if the transaction had been consummated at the beginning of the period presented, nor is the information intended to be indicative of future operating results.

The pro forma consolidated financial information for the year ended June 30, 2008 and 2007 are as follows:

	Year Ended June 30, 2008		Year Ended June 30, 2007	
	As Reported	Pro Forma	As Reported	Pro Forma
Oil and natural gas revenues	$ 4,256,128	$ 2,778,773	$ 1,866,878	$ 38,633
Loss from operations	$ (3,510,558)	$ (3,740,623)	$ (4,348,524)	$ (4,352,996)
Net loss	$ (1,570,974)	$ (1,705,917)	$ (1,810,211)	$ (1,813,163)
Loss per common share – basic and diluted	$ (.06)	$ (.07)	$ (.07)	$ (.07)

Note 5 – Property and Equipment

As of June 30, 2008 and 2007 our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2008	June 30, 2007
Oil and natural gas properties		
Property costs subject to amortization	$ 15,105,766	$ 4,187,440
Less: Accumulated depreciation, depletion, and amortization	(632,040)	(652,439)
Unproved properties not subject to amortization	7,573,507	1,924,552
Oil and natural gas properties, net	$ 22,047,233	$ 5,459,553
Other property and equipment		
Furniture, fixtures and equipment, at cost	231,841	173,205
Less: Accumulated depreciation	(70,814)	(18,333)
Other property and equipment, net	$ 161,027	$ 154,872

Note 6 – Asset Retirement Obligations

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following is a reconciliation of the beginning and ending asset retirement obligation for the year ended June 30, 2008:

	Year Ended 2008	Year Ended 2007
Asset retirement obligations – beginning of period	$ 140,998	$ 123,679
Liabilities incurred	170,890	—
Liabilities settled	—	—
Liabilities sold (See Note 4)	(153,886)	—
Accretion	20,196	17,319
Revisions to previous estimates	36,858	—

Asset retirement obligations – end of period	$ 215,056	$ 140,998

Note 7 – Stockholders' Equity

During the year ended June 30, 2008, three outside directors each received 8,633 shares of restricted common stock as part of a compensation plan for directors. The same outside directors each received 12,414 shares of restricted common stock as part of their compensation plan during the year ended June 30, 2007. All issuances of common stock were subject to vesting terms per individual stock agreements.

We entered into a one-year consulting agreement in February 2008 for investor relations services. As compensation for services, we issued the consultant 50,000 shares of restricted common stock, which is subject to vesting, through December 2008. Previously, we had entered into a one-year consulting agreement with the same service provider, effective November 1, 2006, for 50,000 shares of restricted common stock, which were subject to vesting over a twelve month period.

During the year ended June 30, 2008 and 2007, 8,306 shares of common stock were issued through exercises of 14,463 warrants.

During the year ended June 30, 2007, 16,987 shares of common stock were issued through exercises of 25,000 warrants.

During the year ended June 30, 2007, we reclassified $790,500 from temporary to permanent equity. Under the terms of a private placement of 351,335 shares of our common stock, which we closed on June 10, 2006, the stock subscription agreement was subject to a registration rights agreement requiring us to use our reasonable efforts to register the stock

Note 7 – Stockholders' Equity (Continued)

subsequent to the demand of 40% of the holders of such stock. Such demand could not become effective, however, until the price of our common stock exceeded at least $14.23 per share, (approximately 6.3 times the subscription price). There were no specified damages for our failure to register, nor a specified timetable for obtaining such registration, except that the registration was to be undertaken by us as soon as practicable and was to stay effective for 120 days, or if such registration statement was on Form S-3 and provided for sales of securities from time to time pursuant to Rule 415 under the Securities Act, for up to one year. Until the demand registration right terminated, we classified the proceeds as "temporary equity". We believe the demand registration rights terminated as of June 10, 2007, as all holders were able to freely sell their shares under Rule 144. Consequently, we reclassified the shares from temporary equity to permanent equity on our balance sheet at June 30, 2007.

Note 8 – Stock-Based Incentive Plan

We have granted option awards to purchase common stock (the "Stock Options") and restricted common stock awards ("Restricted 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"). A total of 600,000 awards to purchase an equal number of 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. There are no shares available for grant under the 2003 Stock Plan and, as of June 30, 2008, 1,325,859 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, through June 30, 2008, with Board of Directors approval, outside of the EPM Stock Plans.

Stock Options and Incentive Warrants

Stock-based compensation expense related to Stock Options and Incentive Warrants for the year ended June 30, 2008 and 2007 was $1,522,661 and $1,286,810, respectively.

During the year ended June 30, 2008, we granted Stock Options to purchase 1,435,000 shares of common stock under the 2004 Stock Plan with a weighted average exercise price of $2.58. During the year ended June 30, 2007, we granted Stock Options to purchase 150,000 shares of common stock under the 2004 Stock Plan with a weighted average exercise price of $2.71. 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 year ended June 30, 2008 and 2007 generally vest quarterly, on a straight line basis, over a period of four years and have a contractual life of ten years. The weighted average assumptions used to calculate the fair value of these Stock Options and the weighted average fair value of each Stock Option granted is as follows:

	Year Ended June 30, 2008	Year Ended June 30, 2007
Expected volatility	93.3%	96.0%
Expected dividends	—	—
Expected term (in years)	6.10	6.10
Risk-free rate	4.10%	4.56%
Fair value per Stock Option	$ 2.01	$ 2.15

We estimated the fair value of Stock Options and Incentive Warrants issued to employees and directors under SFAS No. 123R 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 estimated expected term for "plain vanilla" options allowed by the

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 8 – Stock-Based Incentive Plan (Continued)

Securities and Exchange Commission ("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, 2008, and the changes during the year then ended:

	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, 2007	4,058,500	$ 1.53		
Granted	1,435,000	$ 2.58		
Exercised	(10,000)	$ 0.001		
Canceled, forfeited, or expired	—	—		
Stock Options and Incentive Warrants outstanding at June 30, 2008	5,483,500	$ 1.81	$ 23,514,050	7.5
Vested or expected to vest at June 30, 2008	5,483,500	$ 1.81	$ 23,514,050	
Exercisable at June 30, 2008	3,480,063	$ 1.52	$ 15,928,791	7.0

(1) Based upon the difference between the market price of our common stock on the last trading date of the year and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

The aggregate intrinsic value of Stock Options and Incentive Warrants that were exercised during the year ended June 30, 2008 was $58,790. There were no Stock Options or Incentive Warrants that were exercised during the year ended June 30, 2007.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 8 – Stock-Based Incentive Plan (Continued)

A summary of the status of our unvested Stock Options and Incentive Warrants as of June 30, 2008 and 2007, and the changes during the year ended June 30, 2008 and 2007, is presented below:

	Number of Stock Options and Incentive Warrants	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2006	2,407,458	$ 1.41
Granted	150,000	$ 2.15
Vested	(984,333)	$ 1.38
Canceled, forfeited, or expired	—	—
Unvested at June 30, 2007	1,573,125	$ 1.50
Granted	1,435,000	$ 2.01
Vested	(1,004,688)	$ 1.57
Canceled, forfeited, or expired	—	—
Unvested at June 30, 2008	2,003,437	$ 1.83

The total unrecognized compensation cost at June 30, 2008, relating to non-vested share-based compensation arrangements granted under the EPM Stock Plans and Incentive Warrants was $3,546,465. Such unrecognized expense is expected to be recognized over a weighted average period of 2.8 years.

Restricted Stock

For the year ended June 30, 2008, we granted a total of 75,899 shares of Restricted Stock, of which, 25,899 were under our 2004 Stock Plan. For the year ended June 30, 2007, we granted a total of 107,242 shares of Restricted Stock, of which, 57,242 were under our 2004 Stock Plan. All issuances of common stock are subject to vesting terms per individual Restricted Stock agreements.

During the year ended June 30, 2008 and 2007, we recognized compensation expense of $268,825 and $326,683, respectively, related to Restricted Stock grants.

Note 8 – Stock-Based Incentive Plan (Continued)

The following table sets forth the restricted stock transactions for the years ended June 30, 2008 and 2007:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2006	78,000	$ 2.62
Granted	107,242	$ 2.79
Vested	(125,793)	$ 2.69
Forfeited	—	—
Unvested at June 30, 2007	59,449	$ 2.78
Granted	75,899	$ 4.10
Vested	(84,450)	$ 3.16
Forfeited	—	—
Unvested at June 30, 2008	50,898	$ 4.11

At June 30, 2008, unrecognized stock compensation expense related to Restricted Stock grants totaled $155,462. Such unrecognized expense will be recognized over a weighted average period of 0.5 years.

Note 9 – Commodity Hedging and Price Risk Management Activities

As of February 28, 2007, all of our commodity hedging and price risk management activities had expired and were not renewed.

Note 10 – Income Taxes

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

There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits as of the date of adoption of FIN 48 and through June 30, 2008.

Note 10 – Income Taxes (Continued)

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

	June 30, 2008	June 30, 2007
Current:		
Federal	$ (3,551,036)	$ 9,950,221
State	(98,346)	1,435,081
Total current income tax (benefit) provision	(3,649,382)	11,385,302
Deferred:		
Federal	2,573,023	(10,452,433)
State	(9,095)	(1,571,722)
Total deferred income tax provision (benefit)	2,563,928	(12,024,155)
Total income tax benefit	$ (1,085,454)	$ (638,853)

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

	June 30, 2008	June 30, 2007
Income tax benefit computed at the statutory federal rate:	$ (929,750)	$ (857,172)
Reconciling items:		
State income taxes, net of federal tax benefit	(87,377)	(88,817)
Stock based compensation	425,236	282,784
Deferred tax asset valuation adjustment	(417,058)	151,196
IRC section 199 deduction	(69,771)	(155,284)
Other	(6,734)	28,440
Income tax benefit	$ (1,085,454)	$ (638,853)

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, 2008	June 30, 2007
Deferred tax assets:		
Stock based compensation	$ 286,148	$ 178,452
Accrued bonuses	—	175,000
Net operating loss carryforwards	5,547,567	5,547,567
Other	14,487	34,696
Gross deferred tax assets	5,848,202	5,935,715
Valuation allowance	(5,340,571)	(5,757,629)
Total deferred tax assets	507,631	178,086
Deferred tax liability:		
Oil and natural gas properties	(3,409,560)	(516,087)
Total deferred tax liability	(3,409,560)	(516,087)
Net deferred tax liability	$ (2,901,929)	$ (338,001)

We expect to recover approximately $3.6 million in federal and state income taxes paid during the tax year ended June 30, 2006, as a result of the carry-back of our 2008 income tax loss. Significant intangible drilling costs were incurred during the 2008 fiscal year, of which, we elected to deduct (expense) approximately $10.9 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, which resulted in an increase in our net deferred tax liability as of June 30, 2008.

Note 10 – Income Taxes (Continued)

At June 30, 2008, we have a federal tax loss carryforward of approximately $15.9 million we acquired through 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 which has been disallowed through IRC Section 382.

Note 11 – Related Party Transactions

Laird Q. Cagan, Chairman of our Board of Directors, is a Managing Director and co-owner of Cagan McAfee Capital Partners, LLC ("CMCP"). CMCP performs financial advisory services to us pursuant to a written agreement amended in November 2005, providing for a retainer of $5,000 per month. In addition, Mr. Cagan, as a registered representative of Chadbourn Securities Inc. ("Chadbourn") and a partner of CMCP, has served as the Company's placement agent in private equity financings. Under the current agreement, CMCP may 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. Mr. Cagan receives no compensation for serving as a director or as the Chairman of our Board of Directors.

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

During the year ended June, 2008 and 2007, we expensed and paid CMCP $60,000 through monthly retainers of $5,000. There were no other earned fees by CMCP during the year ended June 30, 2008 and 2007.

Note 12 – Net Loss Per Share

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

	Year Ended June 30	
	2008	2007
Numerator		
Net loss	$ (1,570,974)	$ (1,810,211)
Denominator		
Weighted average number of common shares – basic and diluted	26,786,270	26,706,713
Net Loss per common share – basic and diluted	$ (0.06)	$ (0.07)

The following securities were not included in the computation of diluted loss per share as their effect would have been anti-dilutive:

Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2008
Common stock warrants issued in connection with equity and financing Transactions	$ 1.40	401,058
Stock Options and Incentive Warrants	$ 1.81	5,483,500
Non-vested Restricted Stock	N/A	50,898
		5,935,456

Note 13 – Commitments and Contingencies

Environmental clean-up. On August 3, 2007, we were advised of an oil spill in the Tullos Field near one of our leases. At the request of field agents of the Louisiana Department of Environmental Quality and the Environmental Protection Agency ("EPA"), we agreed to commence a clean-up operation that was completed by the end of August 2007. A detailed analysis of the oil in the spill compared to the Company's produced oil was conducted by an EPA approved laboratory. We believe that the oil in the spill did not originate from our operations, supported by the formal findings of the laboratory. We received insurance reimbursements of $484,197 in October 2007 and $217,668 in March 2008. These reimbursements covered all of our actual cleanup costs except a $5,000 insurance deductible and excluding our legal fees, in-house administrative costs, and any possible EPA expense reimbursements and fines that might be billed.

On May 5, 2008, we received a letter from the EPA proposing a $5,500 fine related to the oil spill. We have also received a bill from the United States Coast Guard of approximately $70,000 for expense reimbursement. We believe these claims are not supported by independent investigation. As of the date of this filing, we have requested further verification from the United States Coast Guard to support their claims, and have entered into a settlement with the EPA where we have agreed to pay the $5,500 fine with no admission of liability.

Litigation. The Company is subject to various lawsuits and other claims 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 establish reserves for specific liabilities in connection with regulatory and legal actions that we deem to be probable and estimable. No amounts have been accrued in our financial statements with respect to any legal or regulatory matters as we believe the matters have a remote chance of resulting in a significant judgment.

In July 2008, a multi-plaintiff lawsuit was filed in the twenty-eighth Judicial District Court, Lasalle Parish, Louisiana, against 15 defendants, including Four Star Development Corporation, a former indirect wholly owned subsidiary of the Company, which was sold on March 3, 2008, as part of our sale of the Tullos Field Area. Plaintiffs claim that the defendants' oil and natural gas exploration, development and production activities on their properties have caused soil and ground water contamination as a result of the release of hydrocarbons and drilling fluids. Plaintiffs seek damages for testing, clean-up and remediation of the properties as well as diminution in their value and mental anguish and emotional distress to the individual plaintiffs, unjust enrichment and punitive damages for alleged concealment of ongoing activities. At this time, we are not a party to the litigation and are unable at this time to determine the exposure, if any, to the Company.

In November 2005, a multi-plaintiff lawsuit was filed in the Fifth Judicial District Court, Richland Parish, Louisiana, against 18 defendants including NGS Sub Corp. and Arkla Petroleum LLC, the Company's direct and indirect wholly owned subsidiaries (the "Subsidiaries"), as working interest owners/operators of various oil and natural gas leases in the Delhi Field. Plaintiffs claim that the defendants' oil and natural gas exploration, development and production activities on their properties have caused soil and ground water contamination as a result of the release of hydrocarbons and drilling fluids. Plaintiffs seek damages for testing, clean-up and remediation of the properties as well as diminution in their value and mental anguish to the individual plaintiffs, unjust enrichment and punitive damages for alleged concealment of ongoing activities.

Defendants have answered plaintiffs' suit denying plaintiffs' claims. Trial is set before a jury in Richland Parish for July13, 2009, and we intend to continue contesting plaintiffs' claims vigorously. Discovery is in process, with Plaintiffs' expert's report due to be filed with the Court by September 26, 2008. Defendants have performed field testing which indicates that any contamination is far less pervasive than we believe plaintiffs are claiming, although Plaintiff's complaints are vague and a full analysis of plaintiffs' claims cannot be completed until their expert report is available for analysis.

While the Delhi Field has been in production for approximately sixty years, NGS Sub Corp. and ARKLA were owner and operator since 2003 and 2002, respectively, until June of 2006. We believe that no contamination of significance has occurred during our ownership of the Delhi Field, and that potential liability for exposure of NGS Sub Corp. results largely through any contractual indemnity of prior working interest owners which NGS Sub Corp. may have assumed for historical operations in the field in its acquisition of the subject oil and gas working interests. At this time, the likelihood or amount of any judgment which might be rendered cannot be determined with any certainty.

Note 13 – Commitments and Contingencies (Continued)

Lease Commitments. We have a non-cancelable operating lease for office space that expires on August 1, 2016. Future minimum lease commitments as of March 31, 2008 under this operating lease are as follows:

Year ended June 30,	
2009	$ 138,089
2010	138,089
2011	138,089
2012	157,268
2013	159,012
Thereafter	490,284

Total	$	1,220,831

Rent expense for the year ended June 30, 2008 and 2007 was $141,866 and $81,268, 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, 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, 2008 is approximately $450,000.

Note 14 — Concentrations of Credit Risk

Major Customers. We market substantially 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, 2008 and 2007. Based on the 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, 2008**	**Year Ended June 30, 2007**
Plains Marketing L.P.	67%	98%
ETC Texas Pipeline, LTD.	26%	—

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. Based on the current demand for oil and natural gas, we do not expect that termination of sales to any of our current purchasers would have a material adverse affect on our ability to find replacement purchasers and to sell our production at favorable market prices.

Cash and Cash Equivalents. 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.

Note 15 – Retirement Plan

Effective February 1, 2007, we implemented a 401(k) Savings Plan which covers all 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 $59,437 and $15,584 for the years ended June 30, 2008 and 2007, respectively.

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

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

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling.

	For the Years Ended June 30	
	2008	**2007**
Oil and Natural Gas Activities		
Property acquisition costs:		
Proved property	$ 2,958,538	$ 725,884
Unproved property	5,648,955	1,192,873
Exploration costs	—	—
Development costs	13,216,175	417,964
Total costs incurred for oil and natural gas activities	$ 21,823,668	$ 2,336,721

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

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 and proved developed oil and natural gas reserves was developed from reserve reports prepared by independent reserve engineers:

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

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
July 1, 2006	460,500	—	25,800	464,800
Revisions of previous estimates	(38,423)	—	(25,800)	(42,723)
Purchases of minerals in place	694,300	—	3,838,000	1,333,967
Production (sales volumes)	(28,977)	—	—	(28,977)
Sales of minerals in place	(3,200)	—	—	(3,200)
July 1, 2007	1,084,200	—	3,838,000	1,723,867
Revisions of previous estimates	(298,793)	274,699	(1,013,358)	(192,987)
Purchases of minerals in place	629,700	1,046,400	7,778,800	2,972,567
Production (sales volumes)	(29,466)	(10,639)	(69,051)	(51,614)
Sales of minerals in place	(433,600)	—	—	(433,600)
July 1, 2008	952,041	1,310,460	10,534,391	4,018,233
Proved developed reserves:				
July 1, 2006	460,500	—	25,800	464,800
July 1, 2007	389,700	—	—	389,700
July 1, 2008	96,167	109,716	561,001	299,383

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 within fractured reservoirs. Natural gas liquids were not separately identified in the July 1, 2007 independent report prepared by Von Gonten.

Purchases of minerals in place during 2007 and 2008, resulted from leasehold acquisitions of proved undeveloped reserves in the Giddings Field that directly offset currently or historically productive wells in the same fractured trend.

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 SFAS No. 69, *Disclosures about Oil and Gas Producing Activities* ("SFAS No. 69"). SFAS No. 69 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, 2008 and 2007 are as follows:

	For the Years Ended June 30 2008	2007
Future cash inflows	$ 390,107,980	$ 97,669,992
Future production costs	(61,351,774)	(29,044,113)
Future development costs	(62,457,700)	(18,616,000)
Future income tax expenses	(95,022,328)	(17,012,000)
Future net cash flows	171,276,178	32,997,879
10% annual discount for estimated timing of cash flows	(74,203,537)	(11,007,581)
Standardized measure of discounted future net cash flows	$ 97,072,641	$ 21,990,298

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

The following table presents the average NYMEX crude oil, natural gas liquid, and natural gas price used to compute future cash inflows for each period:

	2008	2007
Average crude oil price per barrel	$ 138.73	$ 70.68
Average natural gas liquids price per barrel	$ 84.39	$ N/A
Average natural gas price per MMbtu	$ 14.00	$ 6.80

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

	For the Years Ended June 30 2008	2007
Balance, beginning of year	$ 21,990,298	$ 6,511,360
Net changes in sales prices and production costs related to future production	19,582,657	254,874

Changes in estimated future development costs	(27,754,046)	(16,050,414)
Sales of oil and gas produced during the period, net of production costs	(2,910,089)	(434,226)
Net change due to purchases of minerals in place	146,355,022	43,710,638
Net change due to sales of minerals in place	(7,302,851)	(178,245)
Net change due to revisions in quantity estimates	(5,791,427)	(3,013,757)
Previously estimated development costs incurred during the period	2,000,000	86,000
Accretion of discount	2,746,274	651,136
Net change in income taxes	(51,843,197)	(9,547,068)
Balance, end of Year	$ 97,072,641	$ 21,990,298

Note 17 – Subsequent Events

In July 2008 we granted 150,000 Stock Options to a new employee and in August 2008, the board of directors approved a resolution to issue a total of 441,079 shares of Stock Options to our employees as part of their total compensation for employment. The Stock Options are excisable at the closing price of the common stock on the date of issuance or the date of approval by the board of directors. The Stock Options vest in equal amounts quarterly over four years and are subject to other standard terms and conditions as provided by the 2004 Stock Plan. In August 2008, certain employees agreed to accept a total of 46,795 shares of common stock, in lieu of a portion of their fiscal 2008 bonus.

Table of Contents

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

As required by Securities and Exchange Commission Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of the Company's management, including our Chief Executive Officer and the Company's Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the quarter covered by this report. Based on the foregoing, 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 such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, 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, 2008.

Table of Contents

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 temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this annual report.

Changes in Internal Control Over Financial Reporting

There has been no change in the Company's internal control over financial reporting during the quarter ended June 30, 2008 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 2008 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 2008 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 2008 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 2008 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 2008 fiscal year.

PART IV.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 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 beginning on page 60 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.

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* *Chief Executive Officer* *(Principal Executive Officer)*
By:	/s/	*STERLING H. MCDONALD* *Sterling H. McDonald* *Vice President and Chief Financial Officer* *(Principal Financial and Accounting Officer)*

Date: September 24, 2008

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 24, 2008	*/s/ E. J. DIPAOLO* *E. J. DiPaolo*	*Director*
September 24, 2008	*/s/ GENE STOEVER* *Gene Stoever*	*Director*
September 24, 2008	*/s/ WILLIAM DOZIER* *William Dozier*	*Director*
September 24, 2008	*/s/ LAIRD Q. CAGAN* *Laird Q. Cagan*	*Chairman of the Board*
September 24, 2008	*/s/ ROBERT S. HERLIN* *Robert S. Herlin*	*Director*

Table of Contents

INDEX OF EXHIBITS

MASTER EXHIBIT INDEX

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

3.4	Bylaws (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.5	Amended Bylaws (Previously filed as an exhibit to Form 10KSB on March 31, 2004)
4.1	Form of Stock Option Agreement for the Natural Gas Systems 2004 Stock Plan (Previously filed as an exhibit to the Current Report on Form 8–K on April 8, 2005)
4.2	Articles of Merger (Previously filed as an exhibit to Form SB – 2/A on October 19, 2005)
4.3	Form of Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.4	Revocable Warrant Agreement between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Current Report on Form 8-K on June 29, 2005)

4.5	Specimen form of the Company's Common Stock Certificate (Previously filed herewith as an exhibit to Form SB – 2/A on October 19, 2005)
4.6	Securities Purchase Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on May 11, 2005)
4.7	Registration Rights Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on May 11, 2005)
4.8	Stock Grant Agreement, dated as of May 4, 2005, by and between Natural Gas Systems, Inc. and Liviakis Financial Communications, Inc. (Previously filed as an exhibit to the Company's Current Report on Form 8-K on May 11, 2005)
4.9	Herlin Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.10	Revocable Warrant Agreement between Natural Gas Systems, Inc. and Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.11	Amended and Restated Tatum Resources Agreement, dated January 1, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.12	Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP, dated January 1, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.13	McDonald Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.14	Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.15	Natural Gas Systems, Inc. Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.16	Revocable Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.17	Natural Gas Systems, Inc. Revocable Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.18	Registration Rights Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Holders of Common Stock of Natural Gas Systems, Inc. (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.19	Form of Registration Rights Agreement (Previously filed as an exhibit to the Company's Current Report on Form 8-K on October 26, 2004)
4.20	2004 Stock Plan (Previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14C on August 9, 2004)
4.21	2003 Stock Option Plan, adopted September 25, 2003 (Previously filed as an exhibit to the Company's

	Form 8-K on January 24, 2007)
4.22	Second Revocable Warrant Agreement , dated as of September 27, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company's Report on Form 10-KSB on September 28, 2005)

4.23	Stock Option Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Current Report on Form 8-K on June 29, 2005)
4.24	Stock Option Grant Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Current Report on Form 8-K on June 29, 2005)
4.25	Securities Purchase Agreement dated as of January 13, 2006, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on January 20, 2006)
4.26	Amended and Restated Registration Rights Agreement dated as of January 13, 2006, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on January 20, 2006)
4.27	Third Revocable Warrant Agreement, by and between Prospect Energy Corporation and Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB – 2/A on March 3, 2006)
4.28	Amendment No. 1 to the Registration Rights Agreement, by and between Prospect Energy Corporation and Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB – 2/A on March 3, 2006)
4.29	Subordinated Promissory Note, dated March 3, 2006, between Natural Gas Systems, Inc. and Laird Q. Cagan (Previously filed as an exhibit to Form 8-K on March 8, 2006)
10.1	Third Amendment to Consulting Agreement between Liviakis Financial Communications, Inc. and Evolution Petroleum dated November 14, 2006 (Previously filed as an exhibit to Form 10-QSB on February 14, 2007)
10.2	Executive Employment Agreement of Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.3	Executive Employment Agreement of Sterling H. McDonald, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.4	Executive Employment Agreement of Daryl V. Mazzanti, dated June 23, 2005 (Previously filed as an exhibit to Form 8-K on June 29, 2005)
10.5	Master Services Agreement, dated September 29, 2005, by and between the NGS Technologies, Inc. and MTEM, Ltd. (Previously filed as an exhibit on Form 8-K on October 7, 2005)
10.6	Agreement with Chadbourn Securities, Inc., dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
10.7	Agreement with Cagan McAfee Capital Partners, LLC, dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
10.8	Unit Operating Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
10.9	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (Previously filed as an exhibit to Form 8-K on September 22, 2006)

10.10	Asset Purchase and Sale Agreement by and between NGS SUB. CORP. (Seller) and MWM Energy, LLC (Buyer), dated February 15, 2008 (Previously filed as an exhibit to Form 10-Q on May 14, 2008)
10.11	Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (Previously filed as Annex A to Form Schedule 14A on October 29, 2007)
14.1	Code of Business Conduct and Ethics for Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
21.1	List of Subsidiaries of Evolution Petroleum Corporation (Filed herein)
23.1	Consent of Hein & Associates, LLP, independent auditors (Filed herein)
23.2	Consent of W. D. Von Gonten & Co. (Filed herein)
31.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
31.2	Certification of Chief Financial Officer Sterling H. McDonald Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.2	Certification of Chief Financial Officer Sterling H. McDonald Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
99.1	Audit Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)

99.2	Compensation Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.3	Nominating Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)