UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended June 30, 2017

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

For the transition period from to

Commission File Number 001-32942

EVOLUTION PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

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

1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079
(Address of principal executive offices and zip code)
(713) 935-0122
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	NYSE American

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

None
(Title of Class)

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

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: ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes: ☒ No: o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes: ☒ No: o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definition of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o		Accelerated filer ☒
Non-accelerated filer o	(Do not check if a smaller reporting company)	Smaller reporting company o
Emerging growth company o		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2016, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $10.00 on the NYSE American, was $250,722,260.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 7, 2017, was 32,905,982.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2017 Annual Meeting of Stockholders to be filed within 120 days of the end of the fiscal year covered by this report are incorporated by reference into Part III of this report.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

2017 ANNUAL REPORT ON FORM 10-K

TABLE OF CONTENTS

		Page
PART I		
Item 1.	Business	1
Item 1A.	Risk Factors	5
Item 1B.	Unresolved Staff Comments	13
Item 2.	Properties	13
Item 3.	Legal Proceedings	19
Item 4.	Mine Safety Disclosures	20
PART II		21
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	21
Item 6.	Selected Financial Data	23
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	24
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	34
Item 8.	Financial Statements and Supplementary Data	35
Item 9.	Changes In and Disagreements with Accountants on Accounting and Financial Disclosure	64
Item 9A.	Controls and Procedures	64
Item 9B.	Other Information	65
PART III		66
Item 10.	Directors, Executive Officers and Corporate Governance	66
Item 11.	Executive Compensation	66
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	66
Item 13.	Certain Relationships and Related Transactions, and Director Independence	66
Item 14.	Principal Accounting Fees and Services	66
PART IV		67
Item 15.	Exhibits and Financial Statement Schedules	67
	Glossary of Selected Petroleum Terms	68
	Signatures	71
	Exhibit Index	72

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 this Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC"). Furthermore, the assumptions that support our forward-looking statements are based upon information that is currently available and is subject to change. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages. All forward-looking statements attributable to Evolution Petroleum Corporation are expressly qualified in their entirety by this cautionary statement.

We use the terms, "EPM," "Company," "we," "us" and "our" to refer to Evolution Petroleum Corporation, and unless the context otherwise requires, its wholly-owned subsidiaries.

PART I

Item 1. Business

Note: See Glossary of Selected Petroleum Industry Terms at the back of this document - refer to Table of Contents

General

We are an independent oil and gas company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas, onshore in the United States. Our goal is to acquire known crude oil and natural gas resources and exploit them through the application of conventional and specialized technology, with the objective of increasing production, ultimate recoveries, or both. Additional information regarding our operating segment, major customers, revenues and assets can be found in in Item 8. Financial Statements - Notes to Consolidated Financial Statements.

Our operations began in September 2003. In May 2004, our predecessor, Natural Gas Systems, Inc., merged into a wholly-owned subsidiary of Reality Interactive, Inc., an inactive public company, which was renamed Natural Gas Systems, Inc. ("NGS"). In connection with the listing of NGS shares on the American Stock Exchange (currently the NYSE American) in July 2006, NGS was renamed Evolution Petroleum Corporation. Our principal executive offices are located at 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, 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 common stock is traded on the NYSE American (formerly known as the NYSE MKT) under the ticker symbol "EPM".

At June 30, 2017, we had five full-time employees, not including contract personnel and outsourced service providers. None of the Company's employees are currently represented by a union, and the Company believes that it has excellent relations with its employees. 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 other non-core functions.

Business Strategy

Our business strategy is to acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology to increase production, ultimate recoveries, or both.

Our principal assets include interests in a CO_2 enhanced oil recovery project in Louisiana's Delhi field and the natural gas liquids recovery plant in the Delhi field. We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain financial control of our assets for the benefit of our shareholders.

Delhi Field - Enhanced Oil Recovery - Onshore Louisiana

Our working and royalty interests in the Delhi Holt-Bryant Unit in the Delhi field ("Unit"), located in Northeast Louisiana, are currently our sole producing assets. The Unit is approximately 13,636 acres in size and has had a prolific production history totaling approximately 195 million bbls of oil through primary and limited secondary recovery operations since its discovery in the mid-1940s. At the time of our purchase of the field in 2003, the Unit had minimal production. We conveyed our working interest in the field to a subsidiary of Denbury Resources, Inc. in May 2006 for $50 million for the purpose of installing an enhanced oil recovery ("EOR") project in the field. We retained a 23.9% reversionary working interest upon payout of the project, as defined. Since EOR production began in March 2010, the Unit has produced over 14 million bbls of oil.

We own two types of interests in the Unit:

- 7.2% of overriding royalty interests that are in effect for the life of the Unit and mineral royalty interests, free of all operating and capital cost burdens; and

- A 23.9% working interest with an associated 19.0% net revenue interest. The working interest reverted to us effective November 1, 2014. Upon occurrence of this contractual payout, we began bearing 23.9% of all operating expenses and capital expenditures.
- The above interests are separate and give us a combined net revenue interest of 26.2%.

Our independent reservoir engineers, DeGolyer and MacNaughton, assigned the following estimated reserves net to our interests at Delhi as of June 30, 2017. Natural gas and natural gas liquids are converted to oil equivalent volumes at the ratio of six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil.

- 10.1 million bbls of proved oil equivalent reserves, with a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $83 million, and PV-10* of $111 million
- 5.3 million bbls of probable** oil equivalent reserves
- 3.2 million bbls of possible** oil equivalent reserves

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* PV-10 of Proved reserves is a non-GAAP measure, reconciled to the Standardized Measure at "Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues" under *Item 2. Properties* of this Form 10-K. Both the Standardized Measure and PV-10 are based on the average first day of the month net commodity prices received at the Delhi field in the twelve months ending June 30, 2017, which were $46.65 per barrel of oil and $20.48 per barrel of natural gas liquids ("NGL"). Probable and possible reserves are not recognized as GAAP nor is there a comparable GAAP measure for probable and possible reserves.

** With respect to the above reserve numbers, estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered, generally described as having a 50% probability of recovery. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. These three reserve categories have not been adjusted to different levels of recovery risk among these categories and are therefore not comparable and are not meaningfully combined.

The operator originally planned six primary phases for the installation of the CO_2 flood in the Delhi field. Four of these phases have been completed as of June 30, 2017 and two remain undeveloped. One of the remaining two phases (Phase V) is reflected as proved undeveloped in our current reserves report and the other was removed from proved reserves (Phase VI) as it was not deemed economic under current pricing guidelines for SEC purposes.

Phase I began CO_2 injection in November 2009. First oil production response occurred in March 2010 and production in the field increased to approximately 1,000 gross barrels of oil per day by December 2010.

Implementation of Phase II, which was more than double the size of Phase I, commenced with incremental CO_2 injection at the end of December 2010. First oil production response from Phase II occurred during March 2011, and field gross production increased to more than 4,000 barrels of oil per day by June 2011.

Phase III was installed during calendar 2011, and was expanded twice during calendar 2011. Production subsequently increased to more than 5,000 barrels of oil per day.

Phase IV was substantially installed during the first six months of calendar 2012. During early calendar 2013, the operator intensified development in the previously redeveloped western side of the field based on production results and new geological mapping that included the results of seismic data acquired over the last few years. Gross field production increased to more than 7,500 barrels of oil per day.

In June 2013, following a fluid release event that consisted of the uncontrolled release of CO_2, water, natural gas and a small amount of oil from a previously plugged well in the southwest part of the field, the operator temporarily suspended CO_2 injection in most of the southwestern tip of the field. The operator has fully remediated the affected area, but has isolated that part of the field with a water curtain.

This fluid release event, along with other contractual disputes, caused the Company to file suit against the operator in December 2013. In June 2016, we reached a settlement with the operator as described in Note 17 – Delhi Field Litigation Settlement.

Subsequent to the reversion of our working interest to us in November 2014, the operator initiated work on the Phase V expansion of the CO_2 flood in the undeveloped eastern part of the field. This project is sometimes referred to as Test Site 5. These operations were suspended shortly after reversion when the operator made significant cuts in its capital budget as a result of declining oil prices. Resumption of this work has been electively delayed due to prevailing oil prices and the partners' allocation of capital to other Delhi projects, primarily the large investment in the NGL plant discussed below. It was further electively delayed based on the conclusion that the economics of the project would be improved if it were implemented after completion of the NGL plant, which has now occurred. We believe that the Phase V expansion of the CO_2 flood has favorable economics, even in this lower price environment, and we expect this project to expand the CO_2 flood to resume within the next two years.

In February 2015, we began construction of an NGL recovery plant in the Delhi Field, which was completed and operational in December 2016. Our net cost for the NGL plant totaled $26.3 million. The NGL plant extracts methane and NGL's from the CO_2 recycle stream. The methane and part of the ethane produced by the NGL plant are used to generate electrical power in the field. The extracted NGL's are sold at the field to a purchaser who transports them by truck to a plant for further processing. In addition to the value of these hydrocarbon products, the increased purity of the CO_2 stream re-injected into the field should result in operational benefits to the CO_2 flood.

Artificial Lift Technology

We previously owned artificial lift technology registered as GARP® (Gas Assisted Rod Pump) that was developed internally by our former Senior Vice President of Operations. Its design is intended to increase production and extend the life of horizontal and vertical wells with gas, oil or associated water production with the expectation of recovering additional reserves at an economically attractive cost per BOE. We received a patent on our GARP® technology on August 30, 2011, which provides U.S. patent protection for the technology through early 2028. We have further filed for a continuation in part to our patent for recent improvements in the technology, including a concentric design which allows the technology to work in narrower diameter casing.

Subsequent to receiving our patent, we entered into demonstration joint venture projects and commercialization projects with industry operators between 2012 and early 2015. Most of these projects were successful in establishing or restoring commercial rates of production. However, with the severe decline in oil prices that began in late 2014, a significant portion of these projects were not sufficiently profitable to justify the incremental capital and operating costs of the technology.

As a result of the declining commodity price environment and reduced capital spending by the industry, the timing for commercial success of this technology was slower than previously anticipated. Based on a strategic review of these operations, we undertook the separation and transfer of these operations to a new entity controlled by the inventor of the technology and certain former employees of the Company, effective December 31, 2015. We invested $108,750 in common and preferred stock and retained a minority interest in the new entity, Well Lift Inc., together with a 5% royalty on all future gross revenues derived from the technology. We have the option to convert our preferred stock investment in Well Lift Inc, into a larger, non-controlling equity stake in the new entity. Consequently, we have retained upside for our shareholders from the potential future success of the technology, while eliminating approximately $1.0 million of annual overhead expenses. We have also retained the right to use the technology in our current wells and any future wells we develop or acquire.

Other Projects

Mississippi Lime—Kay County, Oklahoma

In 2012, we acquired a 45% interest in a joint venture with Orion Exploration, a private company based in Tulsa, Oklahoma. The joint venture was operated by Orion and engaged in the horizontal development of the Mississippi Lime reservoir in Kay County, Oklahoma. Our leasehold position, totaling approximately 6,600 acres, was located in the eastern, more oil-prone side of the play. We drilled one gross salt water disposal well and reached total depth on two horizontally drilled wells in the Mississippi Lime formation. While both wells produced at the fluid rates expected, the quantities of oil and gas were far less than expected. We subsequently reworked both wells to test the role of structure in production, and determined that this play is a structural play requiring substantial geophysical and geological work and expertise in order to be successful, as opposed to a resource play in which engineering is the primary requirement. Accordingly, we elected in fiscal 2013 to reduce our joint venture interest in undeveloped leases to 33.9%, resulting in a $1.2 million reduction in both our net property and accounts payable. In October 2014, we completed the sale of all of our leasehold interests and wells and any associated assets and abandonment liabilities in the Mississippi Lime reservoir to the operator.

Markets and Customers

We market our production to third parties in a manner consistent with industry practices. In the U.S. market where we operate, crude oil and natural gas liquids are readily transportable and marketable. We do not currently market our share of crude oil production from Delhi separately from the operator's share of production. Although we have the right to take our working interest production in-kind, we are currently selling our oil under the Delhi operator's agreement with Plains Marketing L.P. pursuant to the delivery and pricing terms thereunder. The oil from Delhi is currently transported from the field by pipeline, which results in better net pricing than the alternative of transportation by truck. Delhi crude oil production sells at Louisiana Light Sweet ("LLS") pricing which generally trades at a premium to West Texas Intermediate ("WTI") crude oil pricing. The positive LLS Gulf Coast price differential over WTI was approximately $1.67 per barrel during our fiscal year ended June 30, 2017. The differential has narrowed from past years, but we expect that a positive LLS price differential will continue, at least in the near future. Our overall net oil price, including the LLS premium and after all adjustments for transportation, marketing and other price differentials, was $2.28 per barrel less than WTI crude oil prices, as quoted daily on the New York Mercantile Exchange.

Upon completion of the NGL plant in late 2016, we began selling natural gas liquids from the Delhi field to American Midstream Gas Solutions, L.P. Title to these products is transferred to the purchaser at the field and they are transported by truck to the purchaser's processing facility. We receive market prices, less transportation, processing and quality differential fees for the net yield of the individual natural gas liquid components, consisting of propane, butanes, and C5+ (pentanes and heavier components). There is a small component of residual ethane, but the overall yield of products is a higher value mix than is typical for natural gas liquids.

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

	Year Ended June 30,		
Customer	**2017**	**2016**	**2015**
Plains Marketing L.P.	97%	99%	99%
American Midstream Gas Solution, L.P.	3%	—%	—%
All others	—%	1%	1%
	100%	100%	100%

The loss of our purchaser at the Delhi field or disruption to pipeline transportation from the field could adversely affect our net realized pricing and potentially our near-term production levels. The loss of any of our other purchasers would not be expected to have a material adverse effect on our operations.

Market Conditions

Marketing of crude oil, natural gas, and natural gas liquids and the prices we receive are 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 30 years, crude oil price fluctuations have been extremely volatile, with crude oil prices varying from less than $10 to over $140 per barrel. Most recently, the price of oil per barrel has dropped dramatically, starting in the fourth quarter of 2014 and continuing into 2017. It has dropped by more than half since its high in June 2014. Worldwide factors such as geopolitical, macroeconomic, supply and demand, refining capacity, petrochemical production and derivatives trading, among others, influence prices for crude oil. Local factors also influence prices for crude oil and include increasing or decreasing production trends, quality differences, regulation and transportation issues unique to certain producing regions and reservoirs.

Also over the past 30 years, domestic natural gas prices have been extremely volatile, ranging from $1 to $15 per MMBTU. The spot market for natural gas, changes in supply and demand, derivatives trading, pipeline availability, BTU content of the natural gas and weather patterns, among others, cause natural gas prices to be subject to significant fluctuations. Due to the practical difficulties in transporting natural gas, local and regional factors tend to influence product prices more for natural gas than for crude oil.

Competition

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

Seasonality

For a discussion of seasonal changes that affect our business, see *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Other Economic Factors - Seasonality* in this Form 10-K.

Government Regulation

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

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

Insurance

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

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at *www.evolutionpetroleum.com.* These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, or calling (713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider to be immaterial also may adversely affect us.

Risks related to the oil and gas industry and our Company

A substantial or extended decline in oil prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil significantly influences our revenue, profitability, access to capital and future rate of growth. Oil is a commodity and its price is subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, average daily prices for WTI crude oil ranged from a high of $107 per barrel to a low of $27 per barrel over the past three fiscal years ending June 30, 2017. Historically, the markets for oil and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and gas;

- actions of OPEC or other groups of oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals of regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances effecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices. A decline in oil and natural gas liquids prices will reduce our cash flows, borrowing ability, the present value of our reserves and our ability to develop future reserves. We may be unable to obtain needed capital or financing on satisfactory terms. Low oil and natural gas liquids prices may also reduce the amount of oil and natural gas liquids that we can produce economically, which could lead to a decline in our oil and natural gas liquids reserves. Because approximately 83% of our proved reserves at June 30, 2017 are crude oil reserves and 17% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices. 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 liquids prices may adversely affect our financial position.

Our revenues are concentrated in one asset and related declines in production or other events beyond our control could have a material adverse effect on our results of operations and financial results.

Substantially all of our revenues come from our royalty, mineral and working interests in the Delhi field in Louisiana and thus our current revenues are highly concentrated in this field. Any significant downturn in production, oil and gas prices, or other events beyond our control which impact the Delhi field could have a material adverse effect on our results of operations and financial results. We are not the operator of the Delhi field, and our revenues and future growth are heavily dependent on the success of operations, which we do not control.

Operating results from oil and natural gas production may decline; we may be unable to acquire and develop the additional oil and natural gas reserves that are required in order to sustain our business operations.

In general, the volumes of production from crude oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire additional properties containing proved reserves or conduct successful development activities, or both, our proved reserves will decline. Our production is heavily dependent on our interests in EOR production that began during March 2010 in the Delhi field. Environmental or operating problems or lack of future investment at Delhi could cause our net production of oil and natural gas liquids to decline significantly over time, which could have a material adverse effect on our financial condition.

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

Substantially all of our property interests are not operated by the Company and also involve other third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Operators of these properties may act in ways that are not in our best interest. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, result in lower production and materially and adversely affect our financial conditions and results of operations.

We are materially dependent upon our operator with respect to the successful operation of our principal asset, which consists of our interests the Delhi field. A materially negative change in our operator’s financial condition could negatively affect operations (or timing thereof) in the Delhi field, and consequently our income (or timing thereof) from the field as well as the value of our interests in the Delhi field.

Our royalty, mineral and working interests in the Delhi field, located in Northeast Louisiana, currently represent our sole producing asset. Over 99% of our revenues come from these interests and thus our current revenues are highly concentrated in this field. Any significant downturn in production or other events beyond our control which impact the Delhi field could have a material adverse effect on our results of operations and financial results (or timing thereof). We are not the operator of the Delhi field. It is operated by a subsidiary of Denbury Resources Inc. (“DNR”). Our revenues and future growth are thus heavily dependent on the success of operations which we do not control.

Further, our CO_2- Enhanced Oil Recovery (“CO_2-EOR”) project in the Delhi field requires significant amounts of CO_2 reserves and technical expertise, the sources of which have been committed by the operator. Additional capital remains to be invested to fully develop this project, further increase production and maximize the value of this asset. The operator's failure to manage these and other technical, environmental, operating, strategic, financial and logistical matters could cause ultimate enhanced recoveries from the planned CO_2- EOR project to fall short of our expectations in volume and/or timing. Such occurrences could have a material adverse effect on us, and our results of operations and financial condition.

Our economic success is thus materially dependent upon the Delhi field operator's ability to: (i) deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome source, (ii) secure its share of capital necessary to fund development and operating commitments with respect to the field and (iii) successfully manage related technical, operating, environmental, strategic and logistical risks, among other things.

We are aware that DNR, which is publicly traded, has disclosed in its public SEC filings certain risks related to its current level of indebtedness and the related financial covenants. They have stated, for example, that their level of indebtedness could have important consequences, including, among others, requiring dedication of a substantial portion of DNR’s cash flow from operations to servicing their indebtedness. They noted that their ability to meet their obligations under their debt instruments will depend in part upon prevailing economic conditions and commodity prices. DNR also noted that it has from time to time deferred development spending for certain projects.

Given the current stress in the global commodity markets and oil and gas in particular, our operator could be materially negatively impacted, which could in turn negatively affect the operator’s ability to operate the Delhi field as well as its financial commitment to the CO_2-EOR project in the field, and thus our interests in the Delhi field could be materially negatively impacted.

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 generally translates into lower reserve 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. Depleted reservoirs require successful application of newer technology to unlock incremental reserves.

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

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

Our growth will be materially dependent upon the success of our future development program. Drilling for crude oil and natural gas and re-working existing wells involve numerous risks, including the risk that no commercially productive crude oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including, but not limited to:

- unexpected drilling conditions;
- pressure fluctuations or irregularities in formations;
- equipment failures or accidents;
- environmental events;
- inability to obtain or maintain leases on economic terms, where applicable;
- adverse weather conditions;

- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as horizontal drilling or CO_2 injection or other injectants do not guarantee that we will find and produce crude oil and/or natural gas in our wells in economic quantities. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition. We cannot assure you that our overall drilling success rate or our drilling success rate for activities within a particular geographic area will not decline.

We may also identify and develop prospects through a number of methods, some of which do not include horizontal drilling or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. 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.

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

For the year ended June 30, 2017, one purchaser accounted for 97% of our oil and natural gas revenues. We do not currently market our share of crude oil production from the Delhi field. Although we have the right to take our working interest production in-kind, we are currently accepting terms under the Delhi operator's agreement with Plains Marketing L.P. for the delivery and pricing of our oil at the field. The loss of such large single purchaser for our oil and natural gas production could negatively impact the revenue we receive. We cannot assure you we could readily find other purchasers for our oil and natural gas production. In addition, the crude oil production from the Delhi field is transported by pipeline and if this pipeline transportation were disrupted and we were forced to use alternative transportation methods, our net realized pricing and potentially our near-term production levels could be adversely affected.

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

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

Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and 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. The Standardized Measure and PV-10 do not necessarily correspond to market value.

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

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

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas liquids, we have, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas liquids production, including costless collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments. Derivative arrangements also expose us to the risk of financial loss in some circumstances, including, but not limited to, if:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

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, but not limited to the following:

- our ability to identify and acquire new development or acquisition projects;
- our ability to develop existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;
- the success of our technologies;
- hydrocarbon prices;
- drilling, completion and equipment prices;
- our ability to successfully integrate new properties;
- our access to capital; and
- the Delhi field operator's ability to: (i) deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome, secure all of the development capital necessary to fund its and our cost interests, (ii) successfully manage technical, operating, environmental, strategic and logistical development and operating risks, and (iii) maintain its own financial stability, among other things.

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

Our operations require significant amounts of capital and additional financing may be necessary in order for us to continue our exploitation activities, including meeting potential future drilling obligations.

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

We may be subject to risks in connection with acquisitions because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including, but not limited to:

- recoverable reserves
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the seller's title to properties, which may be less than expected at closing; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Moreover, in the event of such an acquisition, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including, but not limited to:

- our lean management team's capacity could be challenged by the demands of evaluating, negotiating and integrating significant acquisitions and strategic transactions in concert with the Company's on going business demands.
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that my be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.

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, the emission of CO_2 or other greenhouse gases, and other substances and materials produced or used in connection with crude oil and natural gas operations. In addition, we may inherit liability for environmental damages, whether actual or not, caused by previous owners of property we purchase or lease or nearby properties. As a result, we may incur substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us, such as diminishing the demand for our products through legislative enactment of proposed new penalties, fines and/or taxes on carbon that could have the effect of raising prices to the end user.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

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, which can result in (i) damage to or destruction of wells and/or production facilities, (ii) damage to or destruction of formations, (iii) injury to persons, (iv) loss of life, or (v) damage to property, the environment or natural resources. 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 incidental to our business. Environmental events similar to that experienced in the Delhi field in June 2013 could defer revenue, increase operating costs and/or increase maintenance and repair capital expenditures.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers, the loss of any of whom could have a material adverse effect on our operations. In particular, our future success is dependent upon the abilities of Robert S. Herlin, our Chairman of the Board, Randall D. Keys, our President and Chief Executive Officer, and David Joe, Senior Vice President, Chief Financial Officer and Treasurer, to source, evaluate and close deals, raise capital, and oversee our development activities and operations. Presently, the Company is not a beneficiary of any key man life insurance.

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

Our business plan to develop or redevelop crude oil and natural gas resources requires third party oilfield service vendors and various material providers, which we do not control. We also rely on third-party carriers for the transportation and distribution of our production. As our production increases, so does our need for such services and materials. Generally, we do not have long-term agreements with our service and materials 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 or we may not be able to source the materials we need. 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. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelop plans.

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

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

We face strong competition from larger oil and gas companies.

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

We have been, and in the future may become, involved in legal proceedings related to our Delhi interest or other properties or operations and, as a result, may incur substantial costs in connection with those proceedings.

From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our financial condition. Adverse litigation decisions or rulings may damage our business reputation.

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

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

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

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

Risks Associated with Our Stock

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

Our common stock has relatively low trading volume and the market price has been, and is likely to continue to be, volatile. For example, during the fiscal year ending June 30, 2017, our stock price as traded on the NYSE American ranged from $5.12 to $10.20. The variance in our stock price makes it difficult to forecast with 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 fluctuations as a result of factors that are out of our control, such as:

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

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

As of June 30, 2017, our executive officers and directors, in the aggregate, beneficially owned approximately 2.9 million shares, or approximately 8.8% of our beneficial common stock base. JVL Advisors LLC controlled approximately 5.1 million shares or approximately 15.4% of our outstanding common stock. ArrowMark Colorado Holdings LLC controlled approximately 2.5 million shares, or approximately 7.4% of our outstanding common stock. Advisory Research, Inc. also controlled approximately 2.5 million shares, or approximately 7.4% of our outstanding common stock and Blackrock Fund Advisors controlled approximately 2.2 million shares, or approximately 6.6% of our outstanding common stock. As a result, any of these holders could potentially exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

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

Our common stock trades on the NYSE American. Our trading volume increased in fiscal 2017 compared to fiscal 2016, but trading volume in our common stock is relatively low compared to larger companies. During the fiscal year ended June 30, 2017, the daily trading volume in our common stock ranged from a low of 12,316 shares to a high of 521,709 shares, with average daily trading volume of 127,419 shares. Our holders may find it more difficult to sell their shares, should they desire to do so, based on the trading volume and price of our stock at that time relative to the quantity of shares to be sold.

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

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

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

We currently have in place a registration statement which allows the Company to publicly issue up to $500 million of additional securities, including debt, common stock, preferred stock, and warrants. At any time we may make private offerings of our securities. The shelf registration is intended to provide greater flexibility to the company in financing growth or changing our capital structure. 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 any 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.

Continued payment of dividends on our common stock could be impacted.

Our Board of Directors declared cash dividends on our common stock for the first time in December 2013 and we have declared and paid quarterly cash dividends since that time. However, there is no certainty that dividends will be declared by the Board of Directors in the 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 and business plan, restrictions contained in current or future debt instruments, contractual covenants or arrangements we may enter into, our anticipated capital requirements and other factors that our board of directors may think are relevant. Accordingly, there is no guarantee that we will be able or choose to continue to pay cash dividends on our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Certain parts of the information required by Item 2. are contained in Item 1. Business

Oil & Gas Properties

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

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

The SEC sets rules related to reserve estimation and disclosure requirements for oil and natural gas companies. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the trailing 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Subject to limited exceptions, the rules also require that proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

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

Estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered, generally described as having a 50% probability of recovery. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. These three reserve categories have not been adjusted to different levels of recovery risk among these categories and are therefore not comparable and are not meaningfully combined.

Estimated pre-tax future net revenues from the production of Proved reserves discounted at 10% or PV-10 is a financial measure that is not recognized by GAAP. We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies, and that it is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. Further, analysts and investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. We also use this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our Company. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure as defined under GAAP, and reconciled herein *this Item 2. Properties*.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2017

Our proved, probable and possible reserves at June 30, 2017, denominated in equivalent barrels using a conversion ratio of six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil, were estimated by our independent petroleum engineering firm, DeGolyer and MacNaughton ("D&M"). D&M was selected to estimate reserves for our interests in the Delhi field due to their expertise in CO_2-EOR projects and to ensure consistency with the operator. The scope and results of their procedures are summarized in a letter from the firm, which is included as exhibit 99.1 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved, probable and possible reserves as of June 30, 2017. See Note 23 to the consolidated financial statements for additional unaudited reserve information. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $48.85 per barrel of crude oil. The net price per barrel of natural gas liquids was $20.48, which does not have any single comparable reference index price. The NGL price was based on historical prices received. For periods for which no historical price information was available, we used comparable pricing in the area. Pricing differentials were applied based on quality, processing, transportation, location and other pricing aspects for each individual property and product.

Reserves as of June 30, 2017

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)*
PROVED			
Developed (79% of Proved)	6,617	1,333	7,950
Undeveloped (21% of Proved)	1,755	353	2,108
TOTAL PROVED	8,372	1,686	10,058
Product Mix	*83%*	*17%*	*100%*
PROBABLE			
Developed (82% of Probable)	3,577	720	4,297
Undeveloped (18% of Probable)	808	163	971
TOTAL PROBABLE	4,385	883	5,268
Product Mix	*83%*	*17%*	*100%*
POSSIBLE			
Developed (89% of Possible)	2,373	478	2,851
Undeveloped (11% of Possible)	304	61	365
TOTAL POSSIBLE	2,677	539	3,216
Product Mix	*83%*	*17%*	*100%*

*BOE computed using a conversion ratio of 42 gallons of natural gas liquids to one barrel of oil.

The following tables present a reconciliation of changes in our proved, probable and possible reserves by major property, on the basis of equivalent MBOE quantities.

Reconciliation of Changes in Proved Reserves

Proved reserves, MBOE	Delhi Field Proved Total MBOE
June 30, 2016	10,823.4
Production	(768.4)
Revisions, net	3.4
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2017	10,058.4

Reconciliation of Changes in Probable Reserves

Probable reserves, MBOE	Delhi Field Probable Total MBOE
June 30, 2016	4,497.3
Revisions, net	770.7
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2017	5,268.0

Reconciliation of Changes in Possible Reserves

	Delhi Field Possible Total
Possible reserves, MBOE	**MBOE**
June 30, 2016	2,714.0
Revisions, net	502.2
Sales of minerals in place	—
Improved recovery, extensions, and discoveries	—
June 30, 2017	3,216.2

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

The following table provides a reconciliation of PV-10 of our proved properties to the Standardized Measure as shown in Note 23 of the consolidated financial statements.

	For the Years Ended June 30,	
	2017	**2016**
Estimated future net revenues	$ 189,347,437	$ 187,713,581
10% annual discount for estimated timing of future cash flows	78,452,886	86,844,543
Estimated future net revenues discounted at 10% (PV-10)	110,894,551	100,869,038
Estimated future income tax expenses discounted at 10%	(27,956,998)	(22,911,719)
Standardized Measure	$ 82,937,553	$ 77,957,319

Our sole producing assets as of June 30, 2017 and 2016 were our interests in the Delhi field. Additional information about the properties we own can be found in *Item 1. Business*.

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

Our policies regarding internal controls over reserves estimates require such estimates to be prepared by an independent engineering firm under the supervision of our Chairman of the Board, our Chief Executive Officer and a professional petroleum engineer, serving as either an employee of or consultant to the Company. Such reserves estimates are to be in compliance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. Our Chairman of the Board holds B.S. and M.E. degrees from Rice University in chemical engineering and earned an M.B.A. from Harvard University. He has over 30 years of experience in engineering, energy transactions, operations and finance with small independents, larger independents and major integrated oil companies. Our Chief Executive Officer holds a Bachelor of Business Administration from the University of Texas at Austin. He has over 30 years of experience in the energy industry, predominantly with upstream oil and gas companies. Our outside consultant for these reserves estimates is a licensed professional engineer with over 30 years of experience in oil and gas operations and petroleum reservoir engineering and holds a Bachelor of Science in Petroleum Engineering from Texas A&M University. In addition, we engaged another consultant with significant experience in CO_2 enhanced oil recovery projects to advise us on certain technical matters related to the Delhi field. This consultant has more than 25 years of experience, including service with two large firms which are industry leaders. He is a registered professional engineer and holds a Master of Science in Petroleum Engineering from Texas A&M University.

The reserves information in this filing is based on estimates prepared by DeGolyer and MacNaughton, our independent engineering firm. The person responsible for preparing the reserves report with D&M is a Registered Professional Engineer in the State of Texas and a Senior Vice President of the firm. He holds a Bachelor of Science degree in Geology in 1973 from Eastern New Mexico University and earned a Master of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975. He has over 38 years of oil and gas reservoir experience. We provide our engineering firm with property interests, production, current operating costs, current production prices and other information. This information is reviewed by our Senior Management and outside consultant to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. The scope and results of our independent engineering firm's procedures, as well as their professional qualifications, are summarized in the letter included as exhibit 99.1 to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

After completion of the NGL plant in the Delhi field, our remaining proved undeveloped reserves were 2,108 MBOE at June 30, 2017, with associated future development costs of approximately $14.1 million. Our proved undeveloped reserves are comprised of (a) 1,564 MBOE of reserves and $10.9 million of future development costs associated with the Phase V development in the eastern portion of the field and (b) 544 MBOE of reserves and $3.2 million of future development costs associated with a proposed eight-well infill drilling program to increase production and recover reserves which are not believed to be effectively producible with the existing well configuration. The infill project has aspects of both acceleration of production and an increase in ultimate reserves recovery and is being treated as a proved undeveloped project.

During the year ended June 30, 2017 our proved undeveloped reserves changed as follows:

	Oil (MBbls)	NGLs (MBbls)		Total Reserves (MBOE)
June 30, 2016	1,420	2,235		3,655
Revisions to previous estimates	335	(505)		(170)
Conversion to proved developed reserves	—	(1,377)		(1,377)
June 30, 2017	1,755	353	1,755	2,108

We converted 1,377 MBOE of undeveloped reserves as the NGL plant was commissioned in December 2016 and initial production commenced. NGL reserves were revised downward 596 MBOE reflecting lower than originally expected plant production partially offset by 91 MBOE of reserves added by the infill project. The 335 MBOE upward revision for oil is due to 453 MBOE infill project reserves partly offset by a 118 MBOE lower estimate for Phase V.

The initial assignment of proved undeveloped reserves in the Delhi field was made on June 30, 2010, which encompassed a large scale CO_2 enhanced oil recovery project. The operator's development plans for the field have remained essentially unchanged and were originally scheduled to be completed by June 30, 2015, within five years from the initial recording of such proved reserves. Developed reserves are approximately 79% of total proved reserves as of June 30, 2017. However, as a result of the adverse fluid release event in the field in June 2013 and the resulting delay in reversion of our working interest, development of the field has not proceeded as originally scheduled. Expansion of the CO_2 flood to the remaining undeveloped eastern portion of the field commenced subsequent to reversion of our working interest in late calendar 2014. We incurred $3.8 million of capital expenditures before the operator electively deferred this project as a result of a reduction in its cash flows and capital spending from the significant drop in oil prices. This project was further electively deferred as we began work on the NGL recovery plant in the Delhi field. It was determined that the economics of development of the remaining eastern portion of the field would be significantly improved after the NGL plant was completed.

During the year ended June 30, 2015 we authorized the NGL plant project and incurred $5.0 million of related capital expenditures. During the years ended June 30, 2016 and 2017, the Company incurred a further $16.5 million and $4.8 million, respectively, of NGL plant capital expenditures. The NGL plant was completed in December 2016 and we converted approximately 1,377 MBOE of proved undeveloped reserves to developed reserves during the year ended June 30, 2017.

As of June 30, 2017, we had estimated future net capital expenditures of $10.9 million remaining for development of the eastern part of the field. This work was suspended in late 2014 and further deferred until the NGL recovery plant was complete. We believe this project is economic in the current oil price environment and we expect it to be completed within the next two fiscal years. This would be nine years after the initial recording of proved reserves. During this period, we have been continuously developing the Delhi field and have spent over $35 million subsequent to reversion. We also have approximately $3.2 million of future net capital expenditures associated with the infill drilling program described above. Given the long-term nature of CO_2 EOR development projects, we believe that the remaining undeveloped reserves in the Delhi field satisfy the conditions to continue to be treated as proved undeveloped reserves because (1) we initially established the development plan for the Delhi field in 2010 and continue to follow that plan, as adjusted to incorporate the completion of the NGL plant in late 2016 and delays relating to the 2013 fluid release event; (2) we have had significant ongoing development activities at this project that, as budgeted and currently being expended, reflect a significant and sufficient portion of remaining capital expenditures to convert proved undeveloped reserves to proved developed reserves; and (3) the operator has a historical record of completing the development of comparable long-term projects.

As of June 30, 2017, no proved, probable or possible reserves were attributed to (a) the suspended southwestern tip area of the field, (b) the area beneath the inhabited portion of the Town of Delhi in the northeast and (c) the farthest east of the two remaining undeveloped sites in the eastern portion of field (Phase VI) due to the current economics and other technical aspects of our future development plans. In addition, no probable reserves are currently attributed to three smaller reservoirs within the Unit in similar formations with similar production history due to the lower oil price utilized in our reserves calculation. We also do not have proved or probable reserves associated with the Mengel Sand, a separate interval within the Unit that is not currently producing, which was received in the litigation settlement in June 2016.

Sales Volumes, Average Sales Prices and Average Production Costs

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

	Year Ended June 30, 2017		Year Ended June 30, 2016		Year Ended June 30, 2015	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Crude oil (Bbls)	724,523	$ 46.31	658,041	$ 39.71	450,713	$ 61.59
Natural gas liquids (Bbls)	43,907	$ 21.28	491	$ 16.06	1,358	$ 27.41
Natural gas (Mcf)	16	$ (0.25)	1,620	$ 1.79	7,981	$ 3.33
Average price per BOE*	768,433	$ 44.88	658,802	$ 39.68	453,401	$ 61.37
Production costs	**Amount**	**per BOE**	**Amount**	**per BOE**	**Amount**	**per BOE**
Production costs, excluding ad valorem and production taxes	$ 10,621,256	$ 13.82	$ 8,767,490	$ 13.31	$ 9,285,396	$ 20.48
Total production costs, including ad valorem and production taxes	$ 10,835,809	$ 14.10	$ 9,062,179	$ 13.76	$ 9,335,244	$ 20.59

* BOE computed using a conversion ratio of six MCF's of natural gas to one barrel of oil equivalent. Natural gas liquids converted at 42 gallons to one barrel of oil equivalent.

Drilling Activity

Our productive drilling activity during the past three fiscal years ended June 30, 2017 was limited to one fiscal 2015 gross (0.239 net) development well drilled in the Delhi field. We also drilled one gross (0.239 net) water injection well in fiscal 2017 in the Delhi field. No dry wells were drilled in the past three fiscal years.

Present Activities

During fiscal year 2015, we commenced construction of a natural gas liquids ("NGL") recovery plant in the Delhi field, which was completed in December 2016.

During fiscal 2017, we drilled one water injection well as part of a project of four water injection wells connected to the continued development of Phase V in the eastern portion of the Delhi field. We also plan to drill eight infill wells in the field to increase production and ultimate reserves recovery. We have authorized expenditures for these projects totaling approximately $6.0 million. This spending was planned to commence in July 2017, but has been electively deferred by the operator until calendar 2018 based on a near-term capital budget reduction in response to weak oil prices.

For further discussion, see "Highlights for our fiscal year 2017" and "Capital Budget" under *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of this Form 10-K.

Delivery Commitments

As of June 30, 2017, we were not committed to provide a fixed and determinable quantity of oil, NGLs or gas under existing agreements, nor do we currently intend to enter into any such agreements.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest as of June 30, 2017.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	—	—	104	24.8	104	24.8
Natural gas	—	—	—	—	—	—
Total	—	—	104	24.8	104	24.8

During the year ended June 30, 2017, we transferred one well in the Giddings field back to its previous operator under our contractual arrangement and later plugged and abandoned our two remaining wells in the field as none of the three wells were producing at economic rates in the existing price environment. We have no other wells operated by the Company at this time.

Our remaining wells consist solely of those in the Delhi field. Delhi has an estimated 104 productive oil wells. It also has approximately 45 CO_2 injection wells and approximately 20 water injection wells. Certain of these wells may be shut-in from time to time and certain wells can potentially be converted to other purposes. Further, there may be other shut-in or previously abandoned well-bores in the field which can be reactivated. Accordingly, the active well count in the field is subject to change over time.

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2017. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Delhi Field, Louisiana *	9,126	2,180	4,510	1,077	13,636	3,257

When the Company acquired the Delhi field in 2003, the field had been fully developed through primary and secondary recovery and all of such acreage was reflected as developed acreage. With the addition of a CO_2-EOR project in the field, certain acreage is now reflected as undeveloped using tertiary recovery operations. We estimate that our developed acreage currently includes 9,126 gross (2,180 net) acres in the Delhi field, with approximately 4,510 gross (1,077 net) acres attributable to the remaining undeveloped areas in the eastern part of the field. We own a 23.9% working interest in the field, along with certain mineral and royalty interests. We are not the operator of the EOR project.

Our interests includes all depths from the surface of the earth to the top of the Massive Anhydride, including the Delhi Holt Bryant Unit, which is currently under CO_2 flood, and the Mengel Sand Interval, which is within the boundary of the field, but is currently not producing. As the Delhi field is unitized, all acreage, including any undeveloped, nonproductive or undrilled acreage is held by existing production as long as continuous production is maintained in the unit.

* This table excludes acreage attributable to small overriding royalty interests retained in various formations in the Giddings Field area. None of such acreage is currently producing and our interests are subject to expiration if leases are not maintained by others or commercial production is not established. It does not currently appear likely that we will obtain any significant value from these interests.

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

Item 3. Legal Proceedings

See Note 18 – Commitments and Contingencies under *Item 8. Financial Statements* for a description of legal proceedings, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

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

Common Stock

Our common stock is currently traded on the NYSE American under the ticker symbol "EPM". The following table shows, for each quarter of the fiscal years ended June 30, 2017 and 2016, the high and low sales prices for EPM as reported by the NYSE American.

NYSE American: EPM

2017:		High		Low
Fourth quarter ended June 30, 2017	$	8.45	$	6.75
Third quarter ended March 31, 2017	$	10.20	$	7.20
Second quarter ended December 31, 2016	$	10.20	$	6.35
First quarter ended September 30, 2016	$	6.85	$	5.12

2016:		High		Low
Fourth quarter ended June 30, 2016	$	5.97	$	4.45
Third quarter ended March 31, 2016	$	5.12	$	3.60
Second quarter ended December 31, 2015	$	7.54	$	4.70
First quarter ended September 30, 2015	$	6.70	$	4.02

Shares Outstanding and Holders

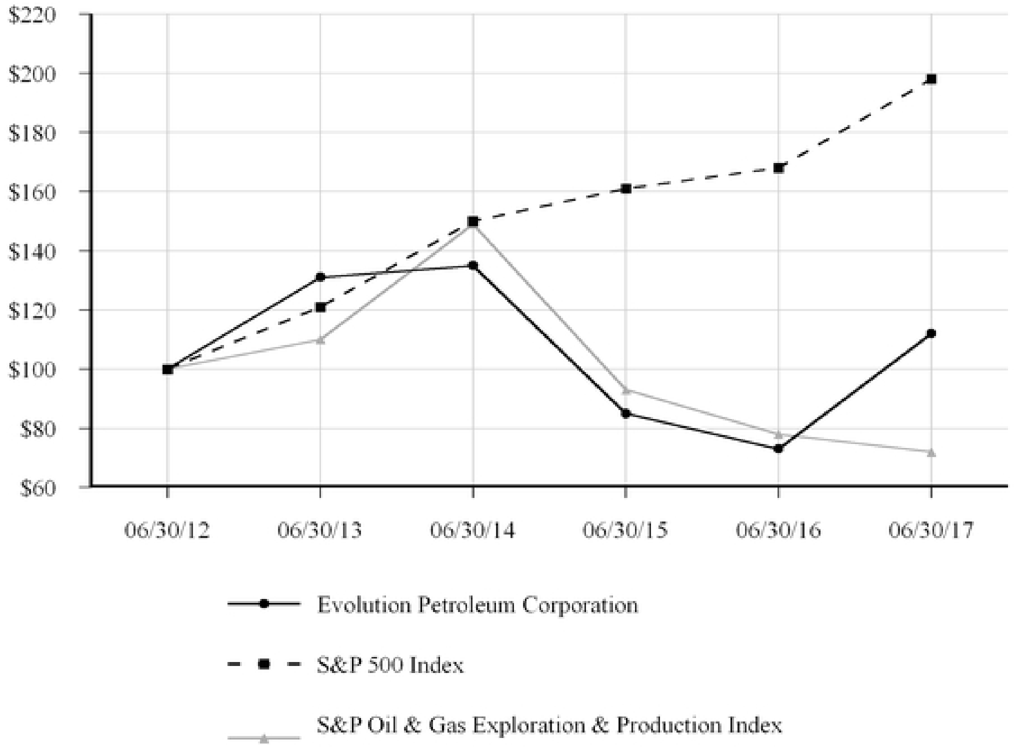
As of June 30, 2017, there were 33,087,308 shares of common stock issued and outstanding, held by approximately 224 holders of record. We estimate there are over 2,000 individuals and entities that hold our stock through nominees.

Dividends

We began paying cash quarterly dividends on our common stock in December 2013, at a rate of $0.10 per share and adjusted the rate to $0.05 per share in March 2015. We increased our dividend rate to $0.065 per share, effective with the dividend payment in December 2016 and later raised its dividend rate to $0.07 per share, effective with the dividend payment in March 2017. As of June 30, 2017, we had paid fifteen consecutive quarterly dividends on our common stock. All dividends on our Series "A" Perpetual Preferred stock were timely declared and paid monthly prior to the redemption of such preferred stock. Any future determination with regard to the payment of dividends will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, applicable dividend restrictions and capital requirements and other factors deemed relevant by the Board of Directors. Under our current revolving credit facility, our ability to continue to pay common stock dividends is dependent on compliance with certain financial covenants related to debt service coverage, as defined in the agreement.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our Common Stock over the period from June 30, 2012 to June 30, 2017 with the cumulative total return of the S&P 500 Index and the S&P Oil & Gas Exploration and Production Index of publicly traded companies over the same period. The graph assumes that $100 was invested on June 30, 2012 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any. The graph is presented in accordance with requirements of the SEC. Shareholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.



Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding Options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(1)
Equity compensation plans approved by security holders:				
Outstanding options	—	(1)	$ —	
Outstanding contingent rights to shares	113,270	(1)	—	
Total	113,270		$ —	1,100,000
Equity compensation plans not approved by security holders	—		—	—
Total	113,270		$ —	1,100,000

(1) As of June 30, 2017, all stock options had been exercised and no shares of common stock were issuable related to outstanding stock options. The Amended and Restated 2004 Stock Plan (the "Plan") provided for the issuance of a total of 6,500,000 common shares. Under the Plan as of June 30, 2017, 3,939,365 common shares had been issued upon the exercise of stock options, 2,382,843 shares of restricted common stock had been issued (of which 391,624 were unvested as of June 30, 2017), contingent restricted stock grants of 145,646 shares had been reserved (of which 113,270 were unvested as of June 30, 2017) and 32,146 remaining reserved shares were released in December 2016 to the Company's authorized but unissued and unreserved shares. The Plan was terminated upon the adoption of 2016 Equity Incentive Plan (the "2016 Plan"), which authorized the issuance of 1,100,000 shares of common stock. During fiscal 2017, no awards were made under the 2016 Plan.

Issuer Purchases of Equity Securities

During the quarter ended June 30, 2017, the Company did not purchase any common stock in the open market under the previously announced share repurchase program and no shares of common stock were surrendered by employees in exchange for required payroll taxes arising from the vesting of restricted stock and/or exercise of stock options.

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.

	June 30,				
	2017	2016	2015	2014	2013
Income Statement Data					
Revenues	$ 34,484,896	$ 26,349,502	$ 27,841,265	$ 17,673,508	$ 21,349,920
Cost of revenues	10,835,809	9,133,111	9,355,613	1,193,573	1,780,738
Depreciation, depletion, and amortization	5,719,405	5,165,120	3,615,737	1,228,685	1,300,207
Accretion expense	59,664	49,054	34,866	41,626	72,312
General and administrative expense	4,985,408	9,079,597	6,256,783	8,388,291	7,495,309
Restructuring charges	4,488	1,257,433	(5,431)	1,293,186	—
Income from operations	12,880,122	1,665,187	8,583,697	5,528,147	10,701,354
Other income (expense)	4,855	32,565,954	(147,619)	(38,836)	(43,165)
Income tax provision	4,840,664	9,570,779	3,444,221	1,891,998	4,029,761
Net income attributable to the Company	$ 8,044,313	$ 24,660,362	$ 4,991,857	$ 3,597,313	$ 6,628,428
Dividends on Series A Preferred Stock	250,990	674,302	674,302	674,302	674,302
Deemed dividend on preferred shares called for redemption	1,002,440	—	—	—	—
Net income attributable to common shareholders	$ 6,790,883	$ 23,986,060	$ 4,317,555	$ 2,923,011	$ 5,954,126
Earnings per common share:					
Basic	$ 0.21	$ 0.73	$ 0.13	$ 0.09	$ 0.21
Diluted	$ 0.21	$ 0.73	$ 0.13	$ 0.09	$ 0.19

	June 30, 2017	June 30, 2016	June 30, 2015	June 30, 2014	June 30, 2013
Balance Sheet Data					
Total current assets	$ 26,142,527	$ 37,086,450	$ 23,693,048	$ 26,304,803	$ 27,436,076
Total assets	88,268,668	97,451,051	69,882,727	65,015,752	66,556,296
Total current liabilities	2,718,894	8,528,908	9,329,257	2,999,726	2,632,750
Total liabilities	19,798,813	21,129,901	21,306,150	13,138,230	11,720,135
Stockholders' equity	68,469,855	76,321,150	48,576,577	51,877,522	54,836,161
Number of common shares outstanding	33,087,308	32,907,863	32,845,205	32,615,646	28,608,969
Working capital, net	$23,423,633	$28,557,542	$14,363,791	$23,305,077	$24,803,326
Cash dividends to common stockholders	$8,432,435	$6,565,823	$9,833,642	$9,723,833	$ —

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, Financial Statements and Supplementary Data. Our discussion and analysis includes forward-looking information that involves risks and uncertainties. It should be read in conjunction with Risk Factors under Item 1A of this Form 10-K, together with the statement of Forward-Looking Information at the beginning of this report for discussion of the risks and uncertainties that could cause our actual results to be materially different from those contained in our forward-looking statements.

Executive Overview

General

We are engaged primarily in the development and production of oil and gas reserves within known oil and gas reservoirs in the United States. We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain control of our assets for the benefit of our shareholders, including a substantial ownership by our directors, officers and staff. By policy, every employee and director maintains a required beneficial ownership of our common stock.

Our strategy is to grow the value of our assets to maximize the value realized by our shareholders. In addition, we plan to continue to return cash to shareholders in the form of quarterly cash dividends and potential stock buybacks under our share repurchase program.

We expect to fund our share of fiscal 2018 expenditures in the Delhi field from working capital and net cash flows from the property.

Highlights for our fiscal year 2017

Financial

- **Our fiscal 2017 net income was 6.8 million, or $0.21 per share.** This marks our sixth consecutive fiscal year of reporting positive net income.
- **We funded all operations, including $7.6 million of capital spending, from internal resources and remained debt free.** We ended the fiscal year with at least $10 million of available liquidity under our credit facility, with no debt outstanding.
- **We returned $8.4 million to common shareholders in the form of cash dividends during fiscal 2017.** With the increase in the quarterly common stock dividend to an annual rate of $0.30 effective September 2017, we have increased dividends by 50% from the annual rate of $0.20 a year ago. We remain committed to our dividend policy and rewarding our long-term shareholders.
- **We completed the redemption of our 8.5% Series A Cumulative Preferred Stock at a cost of $7.9 million.** This will increase funds potentially available to common stockholders by $674,302 per year, or $0.02 per common share.
- **We ended the year with working capital of $23.4 million, down slightly from $28.6 million last year, but after funding all dividends, capital expenditures and the redemption of our preferred stock.** Our strong balance sheet and working capital position have given us the stability to weather this industry downturn and provide an important resource for potential future acquisitions and growth. Our working capital at June 30, 2017 included $23.0 million of cash on hand.

Operations

- **Our net production volumes at Delhi increased by 17%, to 2,105 barrels of oil equivalent per day ("BOEPD") from 1,800 BOEPD in the prior year.** The majority of this increase resulted from the continued conformance and production enhancement workover program in the Delhi field. Natural gas liquid ("NGL") volumes for part of the year also contributed to the production gain.
- **Our oil and NGL revenues were up over 31%, to $34.5 million from $26.1 million in fiscal 2016.** In addition to higher net production volumes, we also experienced a 13% increase in our average price per barrel of oil equivalent ("BOE"), which rose to $44.88, from $39.68 per BOE in the prior year.

- **The Delhi NGL Plant was completed in December 2016 and began production January 2017.** The NGL plant had a final net cost of approximately $26.3 million and has been producing at approximately 70-75% of capacity since initial operations were stabilized. In August 2017, we completed inlet modifications to the CO_2 recycle plant that have enabled the NGL plant to operate at full capacity. The NGL plant has been effective in removing methane and valuable NGL's to increase the purity of the CO_2 stream and is expected to improve the efficiency of the CO_2 flood.

Oil & Gas Reserves (based on SEC defined net oil price of $46.65 and NGL price of $20.48 per barrel)

- **Delhi proved oil equivalent reserves at June 30, 2017 were 10.1 MMBOE.** After adjusting for production of approximately 0.8 MMBOE, our remaining net oil equivalent reserves were essentially flat with the prior year. The Standardized Measure (defined below) increased 6% to $83 million as a result of a higher oil and NGL prices, partially offset by an increase in future operating costs. Proved reserves are 83% oil and 17% natural gas liquids, with 79% of these proved reserves developed and producing.

- **Delhi probable oil equivalent reserves at June 30, 2017 were 5.3 MMBOE**, an 18% increase over the prior year.

- **Delhi possible oil equivalent reserves at June 30, 2017 were 3.2 MMBOE**, a 19% increase over the prior year.

The following table is a summary of our proved, probable and possible reserves for 2017 and 2016:

	Proved			Probable			Possible		
	2017	2016	Change	2017	2016	Change	2017	2016	Change
Reserves MMBOE	10.1	10.8	(6)%	5.3	4.5	18%	3.2	2.7	19%
% Developed	79%	66%	20 %	82%	69%	19%	89%	72%	24%
Liquids %	100%	100%	— %	100%	100%	—%	100%	100%	—%
Standardized Measure ($MM)	$ 83	$ 78	6 %						
PV-10* ($MM)	$ 111	$ 101	10 %						

* PV-10 of Proved reserves is a pre-tax non-GAAP measure. We have included a reconciliation of PV-10 to the unaudited after-tax Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure"), which is the most directly comparable financial measure calculated in accordance with GAAP, in *Item 2. "Properties."* We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful and relevant information to investors because of its wide use by analysts and investors in evaluating the relative monetary significance of oil and natural gas properties, and as a basis for comparison of the relative size and value of our reserves to other companies' reserves. We also use this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our Company. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure as defined under GAAP, and reconciled in *Item 2. Properties*. Probable and possible reserves are not recognized as GAAP, nor is there a comparable GAAP measure.

Projects

Additional property and project information is included under *Item 1. Business*, *Item 2. Properties*, *Item 8. Financial Statements - Notes to the Financial Statements* and *Exhibit 99.1* of this Form 10-K.

Delhi Field EOR—Northeast Louisiana

Proved reserves volumes totaled 10.1 MMBOE with a Standardized Measure of $83 million and a PV-10* value of $111 million compared to the prior year's 10.8 MMBOE with a Standardized Measure of $78 million and a PV-10* value of $101 million. Our reserves quantities in the Delhi field were generally consistent with expectations year over year. Oil production in the field exceeded expectations in the fiscal year, and this led to a 0.5 MMBO (6%) positive revision in proved oil reserves. Results from the NGL plant were below our original expectations, and this resulted in a 0.5 MMBO (22%) negative revision to NGL reserves. Combined, these revisions had virtually no effect on equivalent reserves volumes. However with oil prices more than twice the level of NGL prices, the overall impact on value was positive.

Probable reserve volumes at Delhi were 5.3 MMBOE, an increase of 18% compared to 4.5 MMBOE in the prior year. Possible reserves volumes at Delhi were 3.2 MMBOE, an increase of 19% compared to 2.7 MMBOE in the prior year. Both of these reserve estimates were increased based on positive production performance in the field and its expected positive impact on ultimate reserve recoveries.

Gross production at Delhi in the fourth quarter of fiscal 2017 was 8,559 BOEPD, essentially flat compared to 8,616 BOEPD in the third fiscal quarter. Oil production was 7,540 barrels of oil per day (“BOPD”), down 3% from the third fiscal quarter’s 7,786 BOPD. NGL production in the fourth quarter was 1,019 BOEPD, up 23% from the prior quarter of 830 BOEPD. Oil production was impacted in the fourth quarter due to a weather related power outage, compressor downtime and a planned facility shut down for maintenance.

During the past two years, we have participated in multiple conformance and re-entry projects, as well as workovers to convert idle wells into producers, that were primarily responsible for the increased production rates. We are continuing to evaluate similar projects within the field in order to optimize production and increase ultimate reserve recoveries.

Our cost of purchased CO_2 in the Delhi field, the largest single component of operating costs, is directly tied to the price of oil sold from the field. Therefore this major operating cost has dropped commensurate with the price of crude. Also, we have been successful in realizing a sustained reduction in aggregate CO_2 injection rates without impacting oil production rates. Gross CO_2 injection rates for the year ended June 30, 2017 averaged 73.1 MMcf per day, a decline of 1% compared to the 73.8 MMcf per day during fiscal 2016. We have experienced increases to total lease operating expenses in the second half of fiscal 2017, primarily due to new costs associated with the NGL plant and prolonged issues with optimizing throughput and plant operations. We have also recently increased purchased CO_2 injections, which has resulted in higher costs. Our overall lifting costs for the year were $14.10 per BOE, up slightly from $13.76 per BOE in the prior year. This remains a healthy field margin despite the prolonged low oil price environment.

Following the December 31, 2016 startup of the NGL plant, NGL sales commenced in mid-January 2017 and have been continuous ever since. In the fiscal year, we recorded over $0.9 million of NGL revenues. Our gross NGL production was 459 BOEPD and was sold at an average price of $21.28 per barrel. Production from the NGL plant is transported by truck to a fractionation plant in East Texas. Under the marketing contract, we receive market index pricing for each NGL component, based on the processed yield, less transportation and fractionation (or processing) fees. There may also be a quality deduction for NGL's that do not meet the purchaser's specifications. The current mix of products contains a large percentage (approximately 68%) of higher value NGL's, such as pentanes and butane, and almost no lower value ethane. Market pricing for NGL's during the winter period was seasonally high, but our price was affected by quality deductions on much of the NGL's produced during the fiscal year.

The NGL plant includes an electric turbine to convert methane and part of the ethane processed by the plant to electricity. This turbine is generating power for the NGL plant and is expected to supply excess power to the CO_2 recycle facility, which we expect to lower our overall power costs in the Delhi field. During the initial two quarters of production, with the NGL plant operating at approximately 70-75% of capacity, we have not seen measurable savings in power costs. The NGL plant is accomplishing its primary objective of removing the lighter hydrocarbons (i.e. methane and ethane), thereby increasing the purity of the CO_2 recycle stream and improving the efficiency of the flood. Over time, it is expected to increase the recovery of crude oil in the field. The plant is also providing feedstock to power the electric turbine and producing significant quantities of higher value NGL's for sale.

Remaining estimated capital expenditures for our proved undeveloped reserves amount to $6.71 per BOE for the infill drilling project and Phase V. No remaining capital expenditures are required to develop our probable or possible reserves as these reserves reflect incremental quantities associated with a greater percentage recovery of hydrocarbons in place than the recovery quantities assumed for proved reserves. Looking forward, the timing of plans for continued development of the eastern part of the Delhi field is dependent on the operator’s plans for capital allocation within their portfolio. We continue to believe that this high quality and economically viable project will be executed as planned, subject to oil price volatility.

Liquidity and Capital Resources

We had $23.0 million and $34.1 million in cash and cash equivalents at June 30, 2017 and June 30, 2016, respectively. In addition, we had $10 million of availability under our senior secured reserve-based credit facility on both dates. During the year ended June 30, 2017, we funded our operations and capital spending with cash generated from operations and cash on hand. As of June 30, 2017, our working capital was $23.4 million, compared to working capital of $28.6 million at June 30, 2016. The $5.2 million working capital decrease is primarily due to a $11.0 million decrease in cash, partly offset by a $0.1 million increase in prepaid expenses together with declines of $3.7 million and $1.5 million in accounts payable and accrued liabilities, respectively.

On April 11, 2016, the Company entered into a three-year, senior secured reserve-based credit facility (the "Facility") with MidFirst Bank. The Facility provides a senior secured revolving credit facility with an elected borrowing base of $10 million (the “Borrowing Base”) and a maximum borrowing amount of $50 million. The Facility matures on April 11, 2019, and is secured by substantially all of the Company’s assets.

The Borrowing Base is subject to periodic redeterminations and further adjustments from time to time. The Borrowing Base will be redetermined semi-annually on May 15 and November 15 of each year. The Borrowing Base will also be reduced in certain circumstances such as the sale or disposition of certain oil and gas properties of the Company or its subsidiaries and changes to certain hedging positions. With volatility in commodity prices, our borrowing base and related commitments under the Facility could be reduced in the future. The Facility bears interest, at the Company's option, at either LIBOR plus 2.75% or the Prime Rate, as defined, plus 1.0%. In November 2016 and May 2017, as part of our semiannual borrowing base redeterminations, the lender's commitment, based on our requests, was reaffirmed at $10 million, with our next borrowing base redetermination scheduled for November 2017.

The Facility contains certain covenants, which, among other things, require the maintenance of (i) a total leverage ratio of not more than 3.0 to 1.0, (ii) a debt service coverage ratio of not less than 1.1 to 1.0 and (iii) a consolidated tangible net worth of not less than $40 million, each as defined in the Facility. The Facility also contains other affirmative and negative covenants and events of default. As of June 30, 2017, the Company was in compliance with all covenants contained in the Facility, and no amounts were outstanding under the Facility.

We have historically funded our operations through cash available from operations and working capital. Our primary source of cash in fiscal 2017 were funds generated from the sale of oil and natural gas liquids production. A portion of these cash flows were used to fund our capital expenditures. While we expect to continue to expend capital to further develop the Delhi field, we and the operator have flexibility as to when this capital is spent. Certain projects were recently electively delayed by the operator based on their funds available for capital spending in the current oil price environment. The Company expects to manage future development activities in the Delhi field within the boundaries of its operating cash flow and existing working capital.

Cash Flows from Operating Activities

For the year ended June 30, 2017, cash flows provided by operating activities were $16.5 million, reflecting $19.0 million provided by operations before $2.5 million used by other working capital changes. Of the $19.0 million provided before working capital changes, approximately $8.0 million resulted from net income and $10.9 million was attributable to non-cash expenses and gains.

For the year ended June 30, 2016, cash flows provided by operating activities were $30.7 million, reflecting $28.9 million provided by operations before $1.8 million provided by other working capital changes. Of the $28.9 million provided before working capital changes, approximately $24.7 million resulted from net income and $4.2 million was attributable to non-cash expenses and gains.

For the year ended June 30, 2015, cash flows provided by operating activities were $10.4 million, reflecting $10.9 million provided by operations before $0.5 million used by other working capital changes. Of the $10.9 million provided before working capital changes, approximately $5.0 million resulted from net income and $5.9 million was attributable to non-cash expenses and gains.

Cash Flows from Investing Activities

For the year ended June 30, 2017, investing activities used $10.5 million of cash, consisting primarily of cash capital expenditures of approximately $10.2 million for Delhi field, partially offset by $0.3 million of derivative settlements paid.

For the year ended June 30, 2016, investing activities used $17.6 million of cash, consisting primarily of cash capital expenditures of approximately $21.1 million for the Delhi field, partially offset by $3.6 million of derivative settlement payments received.

For the year ended June 30, 2015, investing activities used $5.0 million of cash, consisting primarily of cash capital expenditures of approximately $4.9 million for Delhi field, $0.3 million for artificial lift technology together with $0.2 million of other assets comprised primarily of GARP® patent costs, partially offset by $0.4 million of proceeds received from the sale of properties in the Mississippi Lime project in October 2014.

Oil and gas capital expenditures incurred, which includes accrued and other noncash expenditures, were $7.6 million, $19.7 million, and $11.2 million, respectively, for the years ended June 30, 2017, 2016, and 2015. These amounts can be reconciled to cash capital expenditures on their respective cash flow statements by adjusting them for related non-cash items presented at Note 12 - Supplemental Disclosure of Cash Flow Information.

Cash Flows from Financing Activities

For the year ended June 30, 2017, financing activities used $17.1 million of cash, comprised of $8.4 million of common stock cash dividends, $0.3 million of preferred dividends, $7.9 million for redemption of preferred stock in November 2016 and $0.5 million of treasury stock acquired through the surrender of shares in satisfaction of payroll liabilities related to vestings of stock-based compensation.

For the year ended June 30, 2016, financing activities provided $0.9 million of cash from $9.6 million of tax benefits related to stock-based compensation partially offset by $7.2 million of dividend payments to common and preferred shareholders and $1.4 million of treasury stock acquisitions primarily attributable to the Company's share buyback program. The tax benefits included a $1.5 million cash refund received from the State of Louisiana for carryback of stock-based compensation deductions to previously filed returns.

During the year ended June 30, 2015, we used $9.2 million in cash for financing activities, comprised of $9.8 million of common stock dividend payments, $0.7 million of preferred stock dividends and $0.3 million of treasury stock acquired through the surrender of shares by certain officers and employees in satisfaction of payroll liabilities related to stock-based compensation and open market purchases under our stock repurchase program, partially offset by cash inflows of $1.6 million from a tax benefit related to stock-based compensation and $0.1 million from stock option exercises.

Capital Budget

During fiscal 2017, our net share of capital expenditures was approximately $7.6 million, of which $4.8 million was related to the NGL plant, with the balance for conformance projects, capital maintenance and repairs and drilling a new water injection well.

An infill drilling program is planned for the second half of fiscal 2018 with an estimated net cost of $3.2 million. This program will consist of three new CO_2 injection wells and five new production wells and will target productive oil zones which we believe are not being swept effectively by the current CO_2 flood. This infill program is expected to both add production and increase ultimate recoveries above the current proved oil reserves.

We have identified and approved additional net capital expenditures over the next fiscal year totaling $2.8 million for water injection and other infrastructure projects in preparation for the Phase V pattern development. In addition, there will continue to be conformance workover projects and maintenance capital expenditures that cannot be estimated accurately at this time. The amount of these projects is not expected to be material to our financial position.

With the NGL plant completed, there are two remaining capital project phases planned to exploit the eastern part of the Delhi field. The first phase of this project, Phase V, was underway in the fall of 2014, immediately after reversion of our working interest. However, based on the decline in oil prices, the operator significantly reduced its capital budget and suspended work on this phase. The resumption of this project is dependent on prevailing oil prices, the availability of capital for such projects and the relative economics of this project versus other projects in the operator's portfolio. We believe this Phase V project, which has an estimated cost of $10.9 million net to our working interest, has favorable economics, even in this lower price environment, and, based on discussions with the operator, expect the related expansion of the CO_2 flood to resume in fiscal 2019. The last phase of the project, Phase VI, has less favorable economics and will require a significant increase in oil prices or other improvements to the economics of the project before it is expected to move forward.

Funding for our anticipated capital expenditures at Delhi over the next fiscal year is expected to be met from cash flows from operations and current working capital.

Liquidity Outlook

Our current liquidity position is very strong, with $23.4 million of working capital, which is significantly in excess of our expected capital needs. We also expect positive cash flow in the future. Our future liquidity is dependent on the realized prices we receive for the oil and natural gas liquids we produce. Commodity prices are market driven and historically volatile, and they are likely to continue to be volatile. In June 2015, the Company began using derivative instruments to reduce its exposure to short term oil price volatility with the goal of achieving a more predictable level of cash flows to support the Company’s capital expenditure and dividend programs. From time to time, the Company has used both fixed price swap agreements and costless collars to manage its exposure to crude oil price risk. We have no derivative commitments at June 30, 2017. While the use of derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. Our future revenues, cash flow, profitability, access to capital and future rate of growth will be significantly impacted by the prices we receive for our production.

Funding for our anticipated capital expenditures over the next two fiscal years is expected to be met from cash flows from operations and current working capital. Our preference is to remain debt free under our current operating plans, but we have access to at least $10 million of availability under a senior secured credit facility if required. In addition we have a maximum of $500 million authorized under an effective shelf registration statement with Securities and Exchange Commission under which we may sell securities from time to time in one or more offerings. We may choose to evaluate and pursue new growth opportunities through acquisitions or other transactions. In that event, we would expect to use our internal resources of cash, working capital and borrowing capacity under our credit facility. It may also be advantageous for us to consider issuing additional equity as part of any potential transaction, but we have no specific plans to do so at this time.

The Board of Directors instituted a cash dividend on our common stock in December 2013 and we have since paid fifteen consecutive quarterly dividends. Distribution of free cash flow in excess of our operating and capital requirements through cash dividends and potential repurchases of our common stock remains a priority of our financial strategy, and it is our long term goal to increase our dividends over time as appropriate. With construction of the NGL plant completed during fiscal 2017, we announced an increase in the common stock cash dividend to $0.065 per share, effective with the dividend payment in December 2016. Following the redemption of our preferred stock and the end of its dividend requirement, we announced a further increase in the common stock dividend to $0.07 per share, effective with the dividend payment in March 2017. In August 2017, the Company announced a further increase in the common stock cash dividend to $0.075 per share, effective with the dividend payment in September 2017. The Board of Directors reviews the quarterly dividend rate in light of current financial results and operations, forecasted financial results, the timing of further expansion of Delhi development and the outlook for crude oil prices.

In May 2015, we established a stock repurchase plan to allow us to acquire up to $5.0 million of our common stock over time. We have repurchased $1.6 million of common stock under the plan, but made no repurchases during fiscal 2017. The timing and amount of repurchases will depend upon several factors, including financial resources and market conditions. In general, our share repurchase program is limited to discretionary funds and is of lesser importance than our primary objectives related to our development capital spending at Delhi and our common stock dividend program. There is no fixed termination date for the repurchase program, and the repurchase program may be suspended or discontinued at any time.

New Accounting Pronouncements Adopted

As discussed in Note 2 "Summary of Significant Accounting Policies," the Company early adopted two new accounting pronouncements, effective for the three months ended September 30, 2016, the first quarter of fiscal year 2017.

ASU 2016-09, Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting. Under previous guidance excess tax benefits were recognized as paid in capital to the extent they reduced cash taxes otherwise payable, and tax deficiencies were recognized as an offset to accumulated excess benefits, if any, or in the statement of operations. The new guidance requires companies to record excess tax benefits and tax deficiencies as income tax benefit or expense in the statements of operations when the awards vest or are settled. Under the required modified retrospective transition, the Company had no cumulative-effect adjustment to retained earnings at the beginning of the period of adoption, as its accumulated excess tax benefits had been completely used in reducing taxable income for the year ended June 30, 2016. The Company elected to prospectively adopt the presentation of excess tax benefits in the operating section of the statements of cash flows. Accordingly, such statements for pre-adoption periods will continue to present excess tax benefits in the financing section. For vestings that occurred in the year ended June 30, 2017, a related tax deficiency of $27,884 was included in the operating section of the statement of cash flows as income tax expense and for the year ended June 30, 2016, $9.7 million of cash provided by tax benefits related to stock-based compensation was included in the financing section of statement of cash flow. Except for the accounting for income taxes discussed above, none of the other provisions in this amended guidance had a material impact on our condensed consolidated financial statements.

ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes.* The update requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. As a result, current deferred tax assets have been netted together with noncurrent deferred income tax liabilities on the June 30, 2017 consolidated balance sheet. The prior years presented were not retroactively adjusted.

Results of Operations

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

	Year Ended June 30,		
	2017	2016	2015
Oil and gas production:			
Crude oil revenues	$ 33,550,698	$ 26,130,762	$ 27,761,291
NGL revenues	934,202	7,885	37,227
Natural gas revenues	(4)	2,895	26,601
Total revenues	$ 34,484,896	$ 26,141,542	$ 27,825,119
Crude oil volumes (Bbl)	724,523	658,041	450,713
NGL volumes (Bbl)	43,907	491	1,358
Natural gas volumes (Mcf)	16	1,620	7,981
Equivalent volumes (BOE)	768,433	658,802	453,401
Crude oil (BOPD, net)	1,985	1,798	1,235
NGLs (BOEPD, net)	120	1	4
Natural gas (BOEPD, net)	—	1	4
Equivalent volumes (BOEPD, net)	2,105	1,800	1,242
Crude oil price per Bbl	$ 46.31	$ 39.71	$ 61.59
NGL price per Bbl	21.28	16.06	27.41
Natural gas price per Mcf	(0.25)	1.79	3.33
Equivalent price per BOE	$ 44.88	$ 39.68	$ 61.37
CO_2 costs	$ 4,477,866	$ 4,090,938	$ 5,050,506
All other lease operating expenses (a)	6,357,943	4,971,241	4,284,738
Production costs	$ 10,835,809	$ 9,062,179	$ 9,335,244
Production costs per BOE	$ 14.10	$ 13.76	$ 20.59
CO_2 volumes (Mcf, gross)	26,664,188	26,996,624	25,615,144
CO_2 volumes (MMcf per day, gross)	73.1	73.8	70.2
Oil and gas DD&A (b)	$ 5,687,903	$ 4,906,123	$ 3,220,990
Oil and gas DD&A per BOE	$ 7.40	$ 7.45	$ 7.10
Artificial lift technology services:			
Services revenues	$ —	$ 207,960	$ 16,146
Cost of service	—	70,932	20,369
Depreciation and amortization expense	$ —	$ 238,475	$ 374,371

(a) Includes ad valorem and production taxes of $214,553, $294,689, and $49,848 for the years ended June 30, 2017, 2016, and 2015, respectively.

(b) Excludes depreciation and amortization expense of artificial lift technology services below and excludes non-operating asset depreciation of $31,502, $20,522, and $20,376 for the years ended June 30, 2017, 2016, and 2015, respectively.

Year ended June 30, 2017 compared with the Year ended June 30, 2016

Net Income. For the year ended June 30, 2017, we generated net income of $6.8 million, or $0.21 per diluted share, on total revenues of $34.5 million. This compares to net income of $24.0 million, or $0.73 per diluted share, on total revenues of $26.1 million for the corresponding year-ago period. The $17.2 million earnings decrease principally resulted from a decrease of $32.6 million in other income, reflecting a prior year $28.1 million litigation settlement, a $3.4 million decrease in derivative instrument gains, and a $1.1 million prior year insurance settlement together with a $0.6 million increase in allocated net income to holders of called preferred shares, partially offset by $8.1 million of higher revenue, $3.1 million of decreased operating costs, and $4.7 million of lower income taxes.

Oil and Gas Production. Revenues increased 31.9% to $34.5 million primarily as a result of a 16.6% increase in production volumes from the year-ago period together with a 13.1% increase in realized prices from $39.68 per equivalent barrel to $44.88 per barrel in the current year. Delhi production and revenues comprise virtually all of our revenues. Net Delhi oil production of 1,985 BOPD was 10.4% higher compared to the prior year as a result of production enhancement and conformance operations in the field. In addition $0.9 million of initial plant NGL sales commenced at the beginning of our third fiscal quarter and averaged 120 BOEPD over the entire fiscal year.

Production Costs. Production costs for the year ended June 30, 2017 were $10.8 million, a 19.6% increase from the prior year. CO_2 costs for the current year were $4.5 million, or 9.5% higher than the prior year, due to a higher CO_2 price partially offset by a 1.2% decrease in purchase volumes as a result of operational efficiencies. The current year average gross CO_2 injection rate was 73.1 MMcf per day, compared to 73.8 MMcf per day in the prior year. For the current year, production costs were $14.10 per barrel on total production volumes, compared to $13.76 per BOE in the prior year. Calculated solely on our Delhi working interest volumes, production costs were $19.01 per barrel of which $8.03 per barrel was CO_2 cost. These latter production costs per barrel exclude production volumes from our royalty interests in the Delhi field as they bear only certain allocated NGL production costs, and are therefore higher than the rates per barrel on our total production volumes.

General and Administrative Expenses (“G&A”). G&A expenses decreased $4.1 million, or 45%, from the prior year, to $5.0 million for the year ended June 30, 2017, primarily due to a $2.6 million decrease in litigation costs, a $0.6 million decrease in stock-based compensation, $0.5 million of lower bonus expense, and $0.5 million of lower salary and benefit expenses.

Other Income and Expenses. For the year ended June 30, 2017, aggregate other items decreased $32.6 million from the prior year due to the $28.1 million Delhi field litigation settlement in the prior year, a $3.4 million decrease in derivative gains and a $1.1 million insurance recovery in the prior year.

Depreciation, Depletion & Amortization Expense (“DD&A”). DD&A increased $0.6 million, or 11%, to $5.7 million for the year ended June 30, 2017 compared to the prior year, due to an increase of $0.8 million in full cost pool depletion, partially offset by a $0.2 million decrease in fixed asset depreciation, which was impacted by the prior year impairment of artificial lift equipment. Compared to the prior year, the increase in full cost pool amortization reflects a 16.6% production increase to 0.8 million BOE, partially offset by a small 0.7% decrease in the amortization rate to $7.40 per BOE.

Year ended June 30, 2016 ("Fiscal 2016") compared with the Year ended June 30, 2015 ("Previous Year")

Net Income. For the year ended June 30, 2016, we generated net income of $24.0 million, or $0.73 per diluted share, on total revenues of $26.3 million. This compares to net income of $4.3 million, or $0.13 per diluted share, on total revenues of $27.8 million for the previous year. The $19.7 million increase in earnings resulted from $28.1 million from the Delhi field litigation settlement, $1.1 million from an insurance recovery, and $3.5 million of derivative gains, partially offset by $6.1 million of higher income taxes, $1.5 million of lower revenue, and $5.4 million of higher operating expenses (which includes a $1.3 million non-recurring restructuring charge).

Oil and Gas Production. Revenues decreased $1.7 million to $26.1 million primarily as a result of a 35% decline in realized prices from $61.37 per equivalent barrel in the previous year to $39.68 per barrel in fiscal 2016, partially offset by a 45% increase in production volumes. The previous year did not include a full twelve months of net production and revenues or production costs as reversion of our working interest did not occur until November 1, 2014. Delhi oil production and revenues comprise virtually all of our revenues. Delhi gross production of 6,778 BOPD was 12% higher that the average gross production of 6,038 BOPD in the previous year as a result of production enhancement and conformance operations in the field.

Production Costs. Production costs for fiscal 2016 decreased $0.2 million to $9.1 million from $9.3 million in the previous year due to a $0.6 million decrease for the Company's operated wells as a result of previous year workover expense, partially offset by $0.4 million increase at the Delhi field. Delhi production costs for fiscal 2016 were $8.9 million, of which $4.1 million was for CO_2 costs, compared to previous year production costs of $8.5 million, of which $5.1 million was for CO_2 costs. Average gross injection volumes decreased from 105,848 Mcf per day in the post-reversion previous year period to

73,762 Mcf per day for the year ended June 30, 2016. For the year ended June 30, 2016, production costs were $13.76 per BOE on total production volumes. Production costs were $18.90 per BOE calculated solely on our Delhi working interest volumes, which includes $8.66 per working interest BOE for CO_2 costs. These latter production costs per BOE exclude production volumes from our royalty interests in the Delhi field, which bear no production costs, and are therefore higher than the rates per BOE on our total production volumes.

Artificial Lift Technology Services. Service revenues were $0.2 million for the year ended June 30, 2016 as a result of fiscal 2016 installations at third party wells. Prior year service revenues and costs were negligible.

Cost of Artificial Lift Technology Services. Cost of technology services were $0.1 million for the year ended June 30, 2016 as a result of fiscal 2016 project activity.

General and Administrative Expenses (“G&A”). G&A expenses increased $2.8 million, or 45%, from the previous year, to $9.1 million for the year ended June 30, 2016, as a result of a $1.7 million increase in litigation costs and a $0.8 million increase in stock compensation expense. Total litigation costs for fiscal 2016 were approximately $2.7 million. In June 2016, we relocated our office to substantially smaller and less expensive premises. This cost savings will be reflected in future periods.

Restructuring charge. Effective December 31, 2015, we recognized a $1.3 million restructuring charge related to the separation of our GARP® artificial lift technology operations. Approximately $0.6 million of the charge consists of the impairment of assets used in that operation and $0.6 million was associated with accrued personnel termination costs to be paid from January 2016 through June 2017. The restructuring charge also includes approximately $0.1 million of non-cash stock compensation expense from the accelerated vesting of restricted stock. As a result of the restructuring, future annual overhead cost savings are estimated to be approximately $1.0 million per year.

Other Income and Expenses. During the year ended June 30, 2016, the Company realized gains of $28.1 million from the Delhi field litigation settlement, $3.4 million of gains on derivatives and $1.1 million from an insurance recovery at the Delhi field.

Depletion & Amortization Expense (“DD&A”). DD&A increased $1.5 million, or 43% to $5.2 million for fiscal 2016 compared to $3.6 million for the previous year as a result of $1.7 million of higher amortization of the full cost pool, partially offset by $0.1 million of lower depreciation on artificial lift technology. Compared to the previous year, production volumes increased 45% to 0.7 million BOE and the amortization rate increased 5% to $7.45 per BOE. Compared to the previous year, the higher amortization rate was due to an 18% decrease in our pool of unamortized costs, partially offset by a 13% decline in proved reserves BOE.

Other Economic Factors

Inflation. Although the general inflation rate in the United States, as measured by the Consumer Price Index and the Producer Price Index, has been relatively low in recent years, the oil and gas industry has experienced unusually volatile price movements in commodity prices, vendor goods and oilfield services. Prices for drilling and oilfield services, oilfield equipment, tubulars, labor, expertise and other services greatly impact our lease operating expenses and our capital expenditures. During fiscal 2017, we have seen a firming of prices for operating and capital costs as a result of improving demand and a closer balance with the supply of goods and services in the industry. Product prices, operating costs and development costs may not always move in tandem.

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

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

Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2017, we are obligated to make under our contractual obligations and commitments. We expect to fund these contractual obligations with cash on hand and cash generated from operations.

	Payments Due by Period				
	Total	1 Year or Less	1 - 3 Years	3 - 5 Years	More than 5 Years
Contractual Obligations					
Operating lease	$ 140,057	$ 73,073	$ 66,984	—	—
Other Obligations					
Asset retirement obligations	1,288,743	35,115	—	—	1,253,628
Total obligations	$ 1,428,800	$ 108,188	$ 66,984	$ —	$ 1,253,628

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost accounting method for our oil and natural gas properties as prescribed by SEC Regulation S-X Rule 4-10. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. Costs are transferred to the full cost pool as the properties are evaluated. As of June 30, 2017, we had no unevaluated properties costs.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense, and the estimated future net cash flows associated with those proved reserves is the basis in determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, additional development activity, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare our reserve estimates, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and / or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves, affecting our quarterly ceiling test calculation and could significantly affect our depletion rate. A 10% decrease in commodity prices used to determine our proved reserves as of June 30, 2017 would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in the Company's proved reserve estimates at June 30, 2017 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $329,000, $696,000 and $1,106,000, respectively.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and gas reserves. The rule allows consideration of new technologies in evaluating reserves, generally limits the designation of proved reserves to those projects forecast to be commenced within five years of the end of the period, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and gas reserves using an average price based on the previous 12-month unweighted arithmetic average first-day-of-the-month price rather than year-end prices, revises the disclosure requirements for oil and gas operations, and revises accounting for the limitation on capitalized costs for full cost companies.

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, 2017, 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. The fair value and expected vesting period of the Company's market-based awards were determined using a Monte Carlo simulation based on the historical volatility of our total common stock return compared to the historical volatilities of the other companies in the index. Vesting of market-based awards is based on the Company's total common stock return compared to a peer group of other companies in our industry with comparable market capitalizations. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option pricing model. This valuation method requires the input of certain assumptions, including expected stock price volatility, expected term of the award, the expected risk-free interest rate, and the expected dividend yield of the Company's stock. The risk-free interest rate used is the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. Because of our limited trading experience of our common stock and limited exercise history of our stock option awards, estimating the volatility and expected term is very subjective. We base our estimate of our expected future volatility on peer companies whose common stock has been trading longer than ours, along with our own limited trading history while operating as an oil and natural gas producer. Future estimates of our stock volatility could be substantially different from our current estimate, which could significantly affect the amount of expense we recognize for our stock-based compensation awards.

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements as of June 30, 2017.

Item 7A. Quantitative and Qualitative Disclosures About Market Risks

Interest Rate Risk

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

Commodity Price Risk

Our most significant market risk is the pricing for crude oil, natural gas and NGL's. We expect energy prices to remain volatile and unpredictable. If energy prices decline significantly, revenues and cash flow would significantly decline. In addition, a non-cash write-down of our oil and gas properties could be required under full cost accounting rules if future oil and gas commodity prices sustained a significant decline. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as, if and when needed. We use derivative instruments to manage our exposure to commodity price risk from time to time based on our assessment of such risk. We primarily utilize swaps and costless collars to reduce the effect of price changes on a portion of our future oil production. We do not enter into derivative instruments for trading purposes. The Company had no positions in derivative instruments at June 30, 2017.

Item 8. Financial Statements

Index to Consolidated Financial Statements

Reports of Independent Registered Public Accounting Firm	36
Consolidated Balance Sheets as of June 30, 2017 and 2016	38
Consolidated Statements of Operations for the Years ended June 30, 2017, 2016, and 2015	39
Consolidated Statements of Cash Flows for the Years ended June 30, 2017, 2016, and 2015	40
Consolidated Statements of Stockholders' Equity for the Years ended June 30, 2017, 2016, and 2015	41
Notes to Consolidated Financial Statements	42

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries (the “Company”) as of June 30, 2017 and 2016, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended June 30, 2017. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Evolution Petroleum Corporation and subsidiaries as of June 30, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2017, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Evolution Petroleum Corporation and subsidiaries’ internal control over financial reporting as of June 30, 2017, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013, and our report dated September 15, 2017 expressed an unqualified opinion on the effectiveness of the Evolution Petroleum Corporation and subsidiaries' internal control over financial reporting.

Hein & Associates LLP
Houston, Texas
September 15, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation

We have audited Evolution Petroleum Corporation and subsidiaries' (the "Company") internal control over financial reporting as of June 30, 2017, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2017, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2017 and 2016, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended June 30, 2017 and our report dated September 15, 2017 expressed an unqualified opinion.

Hein & Associates LLP
Houston, Texas
September 15, 2017

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2017	June 30, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 23,028,153	$ 34,077,060
Receivables	2,726,702	2,638,188
Deferred tax asset	—	105,321
Prepaid expenses and other current assets	387,672	265,881
Total current assets	26,142,527	37,086,450
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas property and equipment, net (full-cost method of accounting)	61,790,068	59,970,463
Other property and equipment, net	40,689	28,649
Total property and equipment	61,830,757	59,999,112
Other assets	295,384	365,489
Total assets	$ 88,268,668	$ 97,451,051
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 2,101,055	$ 5,809,107
Accrued liabilities and other	617,839	2,097,951
State and federal taxes payable	—	621,850
Total current liabilities	2,718,894	8,528,908
Long term liabilities		
Deferred income taxes	15,826,291	11,840,693
Asset retirement obligations, net of current portion	1,253,628	760,300
Total liabilities	19,798,813	21,129,901
Commitments and contingencies (Note 18)		
Stockholders' equity		
Preferred stock, par value $0.001; 5,000,000 shares authorized:8.5% Series A Cumulative Preferred Stock, 1,000,000 shares designated; no shares outstanding at June 30, 2017 as all shares were redeemed November 14, 2016 (Note 10); and 317,319 shares issued and outstanding at June 30, 2016 with a liquidation preference of $7,932,975 ($25.00 per share)	—	317
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 33,087,308 and 32,907,863 shares as of June 30, 2017 and 2016, respectively	33,087	32,907
Additional paid-in capital	40,961,957	47,171,563
Retained earnings	27,474,811	29,116,363
Total stockholders' equity	68,469,855	76,321,150
Total liabilities and stockholders' equity	$ 88,268,668	$ 97,451,051

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Years Ended June 30,		
	2017	**2016**	**2015**
Revenues			
Crude oil	$ 33,550,698	$ 26,130,762	$ 27,761,291
Natural gas liquids	934,202	7,885	37,227
Natural gas	(4)	2,895	26,601
Artificial lift technology services	—	207,960	16,146
Total revenues	34,484,896	26,349,502	27,841,265
Operating costs			
Production costs	10,835,809	9,062,179	9,335,244
Cost of artificial lift technology services	—	70,932	20,369
Depreciation, depletion and amortization	5,719,405	5,165,120	3,615,737
Accretion of discount on asset retirement obligations	59,664	49,054	34,866
General and administrative expenses*	4,985,408	9,079,597	6,256,783
Restructuring charges (income)	4,488	1,257,433	(5,431)
Total operating costs	21,604,774	24,684,315	19,257,568
Income from operations	12,880,122	1,665,187	8,583,697
Other			
Gain on realized derivative instruments, net	43,890	3,315,123	—
Gain (loss) on unrealized derivative instruments, net	(14,132)	124,106	(109,974)
Delhi field litigation settlement	—	28,096,500	—
Delhi field insurance recovery related to pre-reversion event	—	1,074,957	—
Interest and other income	56,855	26,211	35,991
Interest expense	(81,758)	(70,943)	(73,636)
Income before income tax provision	12,884,977	34,231,141	8,436,078
Income tax provision	4,840,664	9,570,779	3,444,221
Net income attributable to the Company	8,044,313	24,660,362	4,991,857
Dividends on preferred stock	250,990	674,302	674,302
Deemed dividend on preferred shares called for redemption	1,002,440	—	—
Net income attributable to common shareholders	$ 6,790,883	$ 23,986,060	$ 4,317,555
Earnings per common share			
Basic	$ 0.21	$ 0.73	$ 0.13
Diluted	$ 0.21	$ 0.73	$ 0.13
Weighted average number of common shares outstanding			
Basic	33,034,480	32,810,375	32,817,456
Diluted	33,110,560	32,861,231	32,924,018

* General and administrative expenses for the years ended June 30, 2017, 2016 and 2015 included non-cash stock-based compensation expense of $1,180,618, $1,750,209, and $943,653, respectively. These years also included litigation expenses of $127,435, $2,729,755, and $1,015,105, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended June 30,		
	2017	2016	2015
Cash flows from operating activities			
Net income attributable to the Company	$ 8,044,313	$ 24,660,362	$ 4,991,857
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	5,775,946	5,211,494	3,664,373
Impairments included in restructuring charge	—	569,228	—
Stock-based compensation	1,180,618	1,809,548	943,653
Accretion of discount on asset retirement obligations	59,664	49,054	34,866
Settlement of asset retirement obligations	(157,910)	—	(223,564)
Deferred income taxes	4,090,919	575,235	1,422,489
Deferred rent	—	—	(17,145)
(Gain) loss on derivative instruments, net	(29,758)	(3,439,229)	109,974
Noncash gain on Delhi field litigation settlement	—	(596,500)	—
Write-off of deferred loan costs	—	50,414	—
Changes in operating assets and liabilities:			
Receivables	(88,514)	484,285	(1,665,261)
Prepaid expenses and other current assets	(135,923)	24,754	378,049
Accounts payable and accrued expenses	(1,626,648)	822,730	551,452
Income taxes payable	(621,850)	431,818	190,032
Net cash provided by operating activities	16,490,857	30,653,193	10,380,775
Cash flows from investing activities			
Derivative settlements received (paid)	(272,318)	3,633,831	—
Proceeds from asset sales	—	—	398,242
Capital expenditure for development of oil and natural gas properties	(10,158,960)	(21,095,901)	(4,890,909)
Capital expenditures for technology and other equipment	(32,260)	(6,883)	(313,059)
Other assets	—	(161,345)	(236,559)
Net cash used by investing activities	(10,463,538)	(17,630,298)	(5,042,285)
Cash flows from financing activities			
Proceeds from the exercise of stock options	—	51,000	141,600
Common share repurchases, including shares surrendered for tax withholding	(459,858)	(1,357,185)	(333,841)
Cash dividends to common stockholders	(8,432,435)	(6,565,823)	(9,833,642)
Cash dividends to preferred stockholders	(250,990)	(674,302)	(674,302)
Redemption of preferred shares	(7,932,975)	—	—
Deferred loan costs	—	(168,972)	(94,075)
Tax benefits related to stock-based compensation	—	9,650,657	1,633,946
Other	32	33	67
Net cash provided (used) by financing activities	(17,076,226)	935,408	(9,160,247)
Net increase (decrease) in cash and cash equivalents	(11,048,907)	13,958,303	(3,821,757)
Cash and cash equivalents, beginning of year	34,077,060	20,118,757	23,940,514
Cash and cash equivalents, end of year	$ 23,028,153	$ 34,077,060	$ 20,118,757

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, 2017, 2016 and 2015

	Preferred		Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value	Shares	Par Value				
Balance, June 30, 2014	317,319	$ 317	32,615,646	$ 32,615	$ 34,632,377	$ 17,212,213	$ —	$ 51,877,522
Issuance of restricted common stock	—	—	213,466	214	(147)	—	—	67
Exercise of stock options	—	—	87,000	87	141,513	—	—	141,600
Common share repurchases, including shares surrendered for tax withholding	—	—	(70,907)	—	—	—	(504,124)	(504,124)
Retirements of treasury stock	—	—	—	(71)	(504,053)	—	504,124	—
Stock-based compensation	—	—	—	—	943,653	—	—	943,653
Tax benefits related to stock-based compensation	—	—	—	—	1,633,946	—	—	1,633,946
Net income	—	—	—	—	—	4,991,857	—	4,991,857
Common stock cash dividends	—	—	—	—	—	(9,833,642)	—	(9,833,642)
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Balance, June 30, 2015	317,319	317	32,845,205	32,845	36,847,289	11,696,126	—	48,576,577
Issuance of restricted common stock	—	—	272,098	272	(239)	—	—	33
Exercise of stock options	—	—	50,000	50	127,450	—	—	127,500
Forfeitures of restricted stock	—	—	(40,758)	(41)	41	—	—	—
Common share repurchases, including shares surrendered for tax withholding	—	—	(218,682)	—	—	—	(1,263,402)	(1,263,402)
Retirements of treasury stock	—	—	—	(219)	(1,263,183)	—	1,263,402	—
Stock-based compensation	—	—	—	—	1,809,548	—	—	1,809,548
Tax benefits related to stock-based compensation	—	—	—	—	9,650,657	—	—	9,650,657
Net income attributable to the Company	—	—	—	—	—	24,660,362	—	24,660,362
Common stock cash dividends	—	—	—	—	—	(6,565,823)	—	(6,565,823)
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Balance, June 30, 2016	317,319	317	32,907,863	32,907	47,171,563	29,116,363	—	76,321,150
Issuance of restricted common stock	—	—	227,889	228	(196)	—	—	32
Exercise of stock options	—	—	35,231	35	77,121	—	—	77,156
Common share repurchases, including shares surrendered for tax withholding	—	—	(83,675)	—	—	—	(537,014)	(537,014)
Retirements of treasury stock	—	—	—	(83)	(536,931)	—	537,014	—
Stock-based compensation	—	—	—	—	1,180,618	—	—	1,180,618
Redemption of preferred shares	(317,319)	(317)	—	—	(6,930,218)	(1,002,440)	—	(7,932,975)
Net income attributable to the Company	—	—	—	—	—	8,044,313	—	8,044,313
Common stock cash dividends	—	—	—	—	—	(8,432,435)	—	(8,432,435)
Preferred stock cash dividends	—	—	—	—	—	(250,990)	—	(250,990)
Balance, June 30, 2017	—	$ —	33,087,308	$ 33,087	$ 40,961,957	$ 27,474,811	$ —	$ 68,469,855

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"), together with its subsidiaries (the "Company", "we", "our" 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 development and production of oil and gas reserves.

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 net income or stockholders' equity. As a result of the separation of our GARP® artificial lift technology operations discussed in Note 7, previously reported revenues for the Delhi field and our artificial lift technology operations have been reclassified as appropriate to crude oil, natural gas liquids, natural gas and artificial lift technology service revenues. Before the reclassification, artificial lift technology revenues included crude oil, natural gas liquids and gas revenues produced by certain of the Company's operated wells that utilized the technology, together with service revenues derived from the use of the Company's technology in third party wells. Previously reported production costs for our artificial lift technology operations have been reclassified as appropriate to oil and gas production costs and cost of artificial lift technology services.

Use of Estimates. The preparation of financial statements in conformity with 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 (a) 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, (b) asset retirement obligations, (c) stock-based compensation, (d) fair values of derivative assets and liabilities, (e) income taxes and the valuation of deferred tax assets and (f) commitments and contingencies. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Note 2 – Summary of Significant Accounting Policies

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

Account Receivable and Allowance for Doubtful Accounts. Accounts receivable consist of joint interest owner obligations due within 30 days of the invoice date, accrued revenues due under normal trade terms, generally requiring payment within 30 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. 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.

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

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

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the "Ceiling Test"). If the capitalized costs of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes, exceed the "Ceiling", this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent, and assuming continuation of existing economic conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices determined as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. Our Ceiling Tests did not result in an impairment of our oil and natural gas properties during the years ended June 30, 2017, 2016 or 2015.

Other Property and Equipment. Other property and equipment includes leasehold improvements, data processing and telecommunications equipment, office furniture and equipment, and oilfield service equipment related to our artificial lift technology operations. These items are recorded at cost and depreciated over expected lives of the individual assets or group of assets, which range from three to seven years. These assets are depreciated using the straight-line method, except for oilfield service equipment related to our artificial lift technology operations, which was depreciated using a method which approximated the timing and amounts of expected revenues from the contract. Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. Repairs and maintenance costs are expensed in the period incurred.

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

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

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, certificates of deposit, accounts receivable, accounts payable and derivative instruments. Except for derivatives, the carrying amounts of these approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the Company’s derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors.

Stock-based Compensation. We estimate the fair value of stock-based compensation awards on the grant date to provide the basis for future compensation expense. Service-based and performance-based Restricted Stock and Contingent Restricted Stock awards are valued using the market price of our common stock on the grant date. Market-based awards are valued using a Monte Carlo simulation based on the historical volatility of the Company's total stock return compared to the historical volatilities of other companies or indices to which we compare our performance. This Monte Carlo simulation also provides an expected vesting period. We use the Black-Scholes option-pricing model to determine grant date fair value of any Stock Option or Incentive Warrant awards. For service-based awards, stock-based compensation is recognized ratably over the service period. For performance-based awards, stock based compensation is recognized ratably over the expected vesting period when it is deemed probable, for accounting purposes, that the performance goal will be achieved. The expected vesting period may be shorter than the remaining term. For market-based awards, stock-based compensation expense is recognized ratably over the expected vesting period, so long as the award holder remains an employee of the Company. Total compensation expense is independent of vesting or expiration of the awards, except for termination of service.

Revenue Recognition* - *Oil and Gas. 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.

Revenue Recognition* - *Artificial Lift Technology. Our artificial lift technology operations generated revenues under contractual arrangements. Under these contracts, we were required to bear part or all of the incremental installation and capital costs for the technology. We evaluated the substance of each contractual arrangement and recognized revenues over the life of the contract as the earnings process was determined to be complete. We likewise charged our related costs, including both capital expenditures and operating expenses, to operating costs in a manner which either matched these costs to the timing of expected revenues, where appropriate, or charged these costs to the accounting period in which they were incurred where it was not appropriate to capitalize or defer them to match with revenues.

Derivative Instruments. The Company has used and may continue to use derivative transactions to reduce its exposure to oil price volatility. All derivative instruments are recorded on the consolidated balance sheet as either an asset or liability measured at fair value. The Company nets its fair value amounts for derivative instruments executed with the same counterparty, where such transactions are covered by an ISDA master agreement that provides for net settlement over the term of the contract and in the event of default or termination of the contract. Although the derivative instruments are intended to provide an economic hedge of the Company’s exposure to commodity price volatility, the Company has not attempted to qualify its derivative instruments for hedge accounting treatment. As a result, changes in the fair value of derivative instruments are recognized as gains or losses in the consolidated statements of operations in the period in which the changes occur. The net cash flows resulting from the payments to and receipts from counterparties as a result of derivative settlements are classified as cash flows from investing activities rather than operating activities. The Company does not intend to enter into derivative instruments for speculative or trading purposes.

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 (net of salvage values) 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 over total proved reserves. Other property, consisting of leasehold improvements, office and computer equipment, vehicles and artificial lift equipment is depreciated as described above in Other Property and Equipment.

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

Earnings (loss) per share. Basic earnings (loss) per share ("EPS") is computed by dividing earnings or loss available to common stockholders by the weighted-average number of common shares outstanding during the period. 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 potentially dilutive common shares had been issued. Potentially dilutive common shares are our outstanding stock options and contingent restricted common stock. We use the treasury stock method to determine the effect of potentially dilutive common shares on diluted EPS, unless the effect would be anti-dilutive. Under this method, exercise of stock options and, under certain conditions, contingent restricted common stock is assumed to have occurred at the beginning of the period (or at time of issuance, if later) and common shares are assumed to have been issued. The proceeds from exercise of stock options and unamortized stock compensation expense related to restricted common stock are assumed to be used to repurchase common stock at the average market price during the period. The incremental shares (the difference between the number of shares assumed issued and the number of shares assumed repurchased) are included in the denominator of the diluted EPS computation. Contingent restricted stock is included in the computation of diluted shares, if dilutive, when the underlying performance conditions either (i) were satisfied as of the end of the reporting period or (ii) would be considered satisfied if the end of the reporting period were the end of the related contingency period.

New Accounting Pronouncements Not Yet Adopted.

In August 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2015-14, which defers the effective date of ASU 2014-09 *Revenue from Contracts with Customers (Topic 606) ("* ASU 2014-09") by one year and allows entities the option to early adopt the new revenue standard as of the original effective date. Issued in May 2014, ASU 2014-09 provided guidance on revenue recognition on contracts with customers to transfer goods or services or on contracts for the transfer of nonfinancial assets. ASU 2014-09 requires that revenue recognition on contracts with customers depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. For public companies, ASU 2014-09 is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standard provides for either the full retrospective or modified retrospective transition methods. We expect to adopt this standard using the modified retrospective method. The Company expects that additional disclosures will be required as a result of adopting ASU 2014-09 and is currently assessing the impact of the guidance on its consolidated financial statements.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities* ("ASU 2016-01"). The pronouncement requires equity investments (except those accounted for under the equity method of accounting, or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income, requires public business entities to use the exit price notion when measuring the fair value of financial instruments for disclosure purposes, requires separate presentation of financial assets and financial liabilities by measurement category and form of financial asset, and eliminates the requirement for public business entities to disclose the method(s) and significant assumptions used to estimate the fair value that is required to be disclosed for financial instruments measured at amortized cost. These changes become effective for fiscal years beginning after December 15, 2017. The expected adoption method of ASU 2016-01 is being evaluated by the Company and the adoption is not expected to have a significant impact on the Company’s consolidated financial position or results of operations.

On February 25, 2016, the FASB issued ASU 2016-02 , *Leases* (“ASU 2016-02”), which relates to the accounting for leasing transactions. This standard requires a lessee to record on the balance sheet the assets and liabilities for the rights and obligations created by leases with lease terms of more than twelve months. In addition, this standard requires both lessees and lessors to disclose certain key information about lease transactions. This standard will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We are evaluating the impact the adoption of ASU 2016-02 will have on our consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (“ASU 2016-15”), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific cash flow issues for which current GAAP is either unclear or does not include specific guidance. This standard will be effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years with early adoption permitted, provided that it is adopted in its entirety in the same period. Currently, the Company does not expect the impact of adopting ASU 2016-15 to have a material effect on its consolidated statements of cash flows.

New Accounting Pronouncements Adopted.

The Company early adopted ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes,* to be applied prospectively effective for the three months ended September 30, 2016, the first quarter of our fiscal year. This amended guidance simplifies the balance sheet position presentation and reduces complexity in accounting for deferred income tax assets and liabilities. The update requires that deferred tax assets and liabilities be classified as noncurrent in a classified statement of financial position. As a result, current deferred tax assets have been combined with noncurrent deferred income tax liabilities in the June 30, 2017 consolidated balance sheet. The prior periods presented were not retroactively adjusted.

The Company early adopted ASU 2016-09, *Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting*, effective for the three months ended September 30, 2016. This amended guidance simplifies and improves several aspects of the accounting for employee share-based payment transactions. Under previous guidance excess tax benefits were recognized as paid in capital to the extent they reduced cash taxes otherwise payable, and tax deficiencies were recognized as an offset to accumulated excess benefits, if any, or in the statement of operations. The new guidance requires companies to record excess tax benefits and tax deficiencies as income tax benefit or expense in the statements of operations when the awards vest or are settled. Under the required modified retrospective transition, the Company had no cumulative-effect adjustment to retained earnings at the beginning of the period of adoption, as its accumulated excess tax benefits had been completely used in reducing taxable income for the year ended June 30, 2016. For vestings that occurred during the year ended June 30, 2017, a related tax deficiency of $27,884 was recognized in income tax expense. The Company also elected to prospectively adopt the presentation of excess tax benefits in the operating section of the statements of cash flows. Accordingly, such statements for pre-adoption periods will continue to present excess tax benefits in the financing section. The amended guidance permits entities to make an accounting policy election related to how forfeitures will impact the recognition of compensation cost for stock-based compensation. Entities can continue to estimate the number of awards which are expected to be forfeited prior to the end of the service period as currently required or can elect to account for forfeitures as they occur. Upon early adoption, the Company elected to change its accounting policy to account for forfeitures as they occur. Except for the effect on income tax expense mentioned above, none of the other provisions in this amended guidance had a material impact on our consolidated financial statements.

Note 3 – Receivables

As of June 30, 2017 and 2016 our receivables consisted of the following:

	June 30, 2017	June 30, 2016
Receivables from oil and gas sales	$ 2,722,880	$ 2,637,593
Other	3,822	595
Total receivables	$ 2,726,702	$ 2,638,188

There were no losses from uncollectible accounts receivable, nor any allowance for doubtful accounts in any of the periods presented in these financial statements.

Note 4 – Prepaid Expenses and Other Current Assets

As of June 30, 2017 and 2016 our prepaid expenses and other current assets consisted of the following:

	June 30, 2017	June 30, 2016
Prepaid insurance	$ 169,416	$ 168,681
Prepaid federal and state income taxes	121,232	—
Retainers and deposits	7,553	30,568
Derivative assets, net	—	14,132
Other prepaid expenses	89,471	52,500
Prepaid expenses and other current assets	$ 387,672	$ 265,881

Note 5 – Property and Equipment

As of June 30, 2017 and 2016, our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2017	June 30, 2016
Oil and natural gas properties		
Property costs subject to amortization	$ 84,962,933	$ 77,408,353
Less: Accumulated depreciation, depletion, and amortization	(23,172,865)	(17,437,890)
Unproved properties not subject to amortization	—	—
Oil and natural gas properties, net	61,790,068	59,970,463
Other property and equipment		
Furniture, fixtures, office equipment and other, at cost	135,377	235,752
Less: Accumulated depreciation	(94,688)	(207,103)
Other property and equipment, net	$ 40,689	$ 28,649

As of June 30, 2017 and 2016, all oil and gas property costs were being amortized.

During the year ended June 30, 2017, the Company incurred capital expenditures of $7.1 million for the Delhi field, including approximately $4.8 million for the NGL plant project. We have incurred approximately $26.3 million on a cumulative basis for the NGL plant.

Note 6 – Other Assets

As of June 30, 2017 and 2016, our other assets consisted of the following:

	June 30, 2017	June 30, 2016
Royalty rights	108,512	108,512
Less: Accumulated amortization of royalty rights	(20,346)	(6,782)
Investment in Well Lift Inc., at cost	108,750	108,750
Deferred loan costs	168,972	168,972
Less: Accumulated amortization of deferred loan costs	(70,504)	(13,963)
Other assets, net	$ 295,384	$ 365,489

For further details about our royalty rights and investment in Well Lift Inc. ("WLI"), see Note 7 – Restructuring. These assets were recorded in connection with the separation of our artificial lift technology operations. The Company accounts for its investment in WLI using the cost method, under which any return of capital reduces cost and any dividends paid are recorded as income. Investment value is evaluated for impairment at least quarterly or when management identifies any events or changes in circumstances that may have a significant adverse effect on the fair value of the investment. There is no published market value for this private investment, so it is not practicable to value it at fair market value on a periodic basis.

In April 2016, we entered into a new secured credit facility, incurring $168,972 of deferred loan costs. Our previous credit facility had deferred loan costs of $179,468, which were fully amortized at its expiration in April 2016. During the year ended June 30, 2016, negotiations to obtain a new expanded secured credit facility from our previous lender were curtailed due to market conditions. We determined that $50,414 of deferred legal fees related to this proposed facility were unlikely to be utilized and were charged to expense. In addition, $107,196 of deferred costs incurred for title work in the Delhi field were charged to capitalized costs of oil and gas properties. Amortization of deferred loan costs related to our credit facilities for the years ended June 30, 2017, 2016 and 2015 was $56,541, $46,374 and $48,636, respectively.

Note 7 – Restructuring

Separation of GARP® Artificial Lift Technology Operations

During the quarter ended December 31, 2015, we conducted a strategic review of our GARP® artificial lift technology operations and consummated a plan to separate and transfer these operations to a new entity controlled by the inventor of the technology, our former Senior Vice President of Operations, and certain former employees of the Company. We invested $108,750 in common and preferred stock of the new entity, WLI. We own 17.5% of WLI and our former employees that previously had primary responsibility for our GARP® operations own the balance of the common stock. Our preferred stock is convertible at our option into common stock which would result in our ownership of 42.5% of WLI, based on the current capital structure of WLI. The Company has no contractual exposure to losses of WLI, nor does it have any obligation or agreement to provide additional funding or support to WLI if it is needed. In connection with this transaction, three employees of the Company were terminated. We accrued a restructuring charge based on agreements with the employees covering salary and benefit continuation and an acceleration of vesting of equity awards in exchange for release from liabilities and other provisions including agreements not to compete. At December 31, 2015, we recorded a personnel restructuring charge of $688,205 consisting of $59,339 in stock-based compensation and $628,866 of accrued separation and benefits expense. All of such accrued separation and benefits costs had been settled as of June 30, 2017, and an adjustment of $4,488 was recorded in the current year to reflect the difference between the original accrual and actual expenditures.

Other Restructuring Impairments

Also in connection with the December 2015 separation of GARP®, we transferred our technology assets, including our patents and trademarks, to WLI in exchange for a perpetual royalty of 5% on all future gross revenues associated with the GARP® technology. We reduced the carrying value of these technology assets to our estimate of their expected discounted net present value, which was $108,512. This resulted in an impairment charge of $469,395. In addition, we transferred certain inventory and minor fixed assets to WLI that had no further use in our operations and were deemed to have negligible market or salvage value. This resulted in impairments of $92,901 to equipment inventory and $6,932 to fixed assets, respectively. These impairments totaled $569,228 and are included in restructuring charges.

Note 8 – Accrued Liabilities and Other

As of June 30, 2017 and 2016 our accrued liabilities and other consisted of the following:

	June 30, 2017	June 30, 2016
Accrued incentive and other compensation	$ 413,113	$ 999,172
Accrued restructuring charges	—	419,488
Asset retirement obligations due within one year	35,115	201,896
Accrued royalties, including suspended accounts	17,708	49,580
Accrued franchise taxes	150,062	62,834
Payable for settled derivatives	—	318,708
Accrued - other	1,841	46,273
Accrued liabilities and other	$ 617,839	$ 2,097,951

Note 9 –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 obligations for the years ended June 30, 2017 and 2016:

	Years Ended June 30,	
	2017	2016
Asset retirement obligations—beginning of period	$ 962,196	$ 772,990
Liabilities incurred	52,792	28,505
Liabilities settled	(157,164)	—
Liabilities sold (b)	(47,817)	—
Accretion of discount	59,664	49,054
Revisions to previous estimates	419,072	111,647
Asset retirement obligations — end of period (b)	1,288,743	962,196
Less current asset retirement obligations	(35,115)	(201,896)
Long-term portion of asset retirement obligations	$ 1,253,628	$ 760,300

(a) We conveyed our interest in a well to the previous operator in exchange for the assumption of our asset retirement obligations.

(b) As we have now retired all of our remaining operated wells, our asset retirement obligations as of June 30, 2017 consist entirely of our working interest obligations in the Delhi field.

Note 10 – Stockholders' Equity

Common Stock

As of June 30, 2017, we had 33,087,308 shares of common stock outstanding.

In December 2013, the Board of Directors initiated a quarterly cash dividend on our common stock at a quarterly rate of $0.10 per share. This rate was subsequently adjusted to $0.05 per share during the quarter ended March 31, 2015. During the year ended June 30, 2017, the Board of Directors made two increases to the quarterly cash dividend, resulting in rates of $0.065 per share for the December 31, 2016 dividend payment and $0.07 per share for the March 31, 2017 dividend payment. We paid total cash dividends of $8,432,435, $6,565,823 and $9,833,642 to our common shareholders during the years ended June 30, 2017, 2016 and 2015, respectively.

In May 2015, the Board of Directors approved a share repurchase program covering up to $5 million of the Company's common stock. As of June 30, 2017, we have repurchased 265,762 shares at an average price of $6.05 per share, for total cost of $1,609,008. Under the program's terms, shares are repurchased only on the open market and in accordance with the requirements of the Securities and Exchange Commission. Such shares are initially recorded as treasury stock, then subsequently canceled. The timing and amount of repurchases depends upon several factors, including financial resources and market and business conditions. There is no fixed termination date for this repurchase program, and it may be suspended or discontinued at any time. We have not repurchased any shares since December 2015.

During the year ended June 30, 2017, the Company acquired 83,675 shares of treasury stock at an average cost of $6.42 per share (totaling $537,014) from holders of newly vested stock-based awards to fund the recipients' payroll taxes paid in the year. The treasury shares were subsequently canceled.

During the year ended June 30, 2016, the Company purchased 202,390 shares of treasury stock at an average cost of $5.80 per share (totaling $1,173,899) under its share repurchase program and also acquired 16,292 shares of treasury stock at an average cost of $5.49 per share (totaling $89,503) from holders of newly vested stock-based awards to fund the recipients' payroll taxes paid in the year. All treasury shares were subsequently canceled.

During the year ended June 30, 2015, the Company purchased 63,372 shares of treasury stock at an average cost of $6.87 per share (totaling $435,109) under its share repurchase program and also acquired 7,535 shares of treasury stock at an average cost of $9.16 per share (totaling $69,015) from holders of newly vested stock-based awards to fund the recipients' payroll taxes paid in the year. All treasury shares were subsequently canceled.

Series A Cumulative Perpetual Preferred Stock Called for Redemption

On September 30, 2016, the Company elected to redeem all 317,319 outstanding shares of the Company’s 8.5% Series A Cumulative (perpetual) Preferred Stock. The redemption occurred on November 14, 2016 at the redemption value of $25.00 per share plus all accumulated and unpaid distributions, for an aggregate redemption cost of $7,932,975.

On September 30, 2016, in connection with the planned redemption, the Company recorded a deemed dividend of $1,002,440, representing the difference between the redemption consideration paid and the historical net issuance proceeds of the preferred shares. Accordingly, net income was adjusted for this deemed dividend to determine net income attributable to common shareholders and earnings per common share.

Dividends on the Series A Cumulative Preferred Stock accrued and accumulated at a fixed rate of 8.5% per annum on the $25.00 per share liquidation preference, payable monthly. During the year ended June 30, 2017, we paid cash dividends of $250,990 to holders of our Series A Preferred Stock. During each of the years ended June 30, 2016 and 2015, we paid cash dividends of $674,302.

Tax Treatment of Dividends to Recipients

Based on our current projections for the fiscal year ending June 30, 2017, we expect all preferred and common dividends to be treated for tax purposes as qualified dividend income to the recipients. For the fiscal year ended June 30, 2016, all preferred and common dividends for this fiscal year were treated for tax purposes as qualified dividend income to the recipients. For fiscal year ended June 30, 2015, 100% of cash dividends on preferred stock were treated as qualified dividend income. For the same period, approximately 86% of cash dividends on common shares were treated as a return of capital to stockholders and the remainder of 14% were treated as qualified dividend income.

Note 11—Stock-Based Compensation

At the December 8, 2016 annual meeting, the stockholders approved the adoption of the Evolution Petroleum Corporation 2016 Equity Incentive Plan (the “2016 Plan”), which replaced the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the "2004 Plan"). The 2016 Plan authorizes the issuance of 1,100,000 shares of common stock prior to its expiration on December 8, 2026. Incentives under the 2016 Plan may be granted to employees, directors and consultants of the Company in any one or a combination of the following forms: incentive stock options and non-statutory stock options, stock appreciation rights, restricted stock awards and restricted stock unit awards, performance share awards, performance cash awards, and other forms of incentives valued in whole or in part by reference to, or otherwise based on, our common stock, including its appreciation in value. As of June 30, 2017, 1,100,000 shares were available for grant under the 2016 Plan.

At June 30, 2017, no shares remained available for grant under the 2004 Plan. We were authorized to issue 6,500,000 shares of common stock prior to its expiration on October 24, 2017. In connection with the adoption of the 2016 Plan, the Board terminated the 2004 Plan on December 8, 2016 and 32,146 remaining reserved shares were released to the Company's authorized but unissued and unreserved shares. All outstanding awards granted under the 2004 Plan continue to be subject to the terms and conditions as set forth in the agreements evidencing such awards and the terms of the 2004 Plan. Under these agreements, we have granted option awards to purchase common stock (the "Stock Options"), restricted common stock awards ("Restricted Stock"), contingent restricted common stock awards ("Contingent Restricted Stock") and/or unrestricted fully vested common stock, to employees, directors, and consultants of the Company.

Stock Options

No Stock Options have been granted since August 2008 and all compensation costs attributable to Stock Options have been recognized in prior periods. The following summary presents information regarding outstanding Stock Options as of June 30, 2017, and the changes during the period:

	Number of Stock Options	Weighted Average Exercise Price	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Term (in years)
Stock Options outstanding at July 1, 2016	35,231	$ 2.19		
Exercised	(35,231)	2.19		
Stock Options outstanding at June 30, 2017	—	$ —	$ —	0.0

For the year ended June 30, 2017, there were 35,231 Stock Options exercised with an aggregate intrinsic value of $188,821. For the year ended June 30, 2016, there were 50,000 Stock Options exercised with an aggregate intrinsic value of $131,000. For the year ended June 30, 2015, there were 87,000 Stock Options exercised, with an aggregate intrinsic value of $501,810.

No stock options vested during the years ended June 30, 2017, 2016, and 2015.

Restricted Stock and Contingent Restricted Stock

Prior to August 28, 2014, all Restricted Stock grants contained a four-year vesting period based solely on service. Restricted Stock which vests based solely on service is valued at the fair market value on the date of grant and amortized over the service period.

In August 2014, December 2015 and September 2016, the Company awarded grants of both Restricted Stock and Contingent Restricted Stock as part of its long-term incentive plan. Such grants, which expire after four years if unvested, contain service-based, performance-based and market-based vesting provisions. The common shares underlying the Restricted Stock grants were issued on the date of grant, whereas the Contingent Restricted Stock are reserved from the Plan, but will be issued only upon the attainment of specified performance-based or market-based vesting provisions.

Performance-based grants vest upon the attainment of earnings, revenue and other operational goals and require that the recipient remain an employee of the Company through the vesting date. The Company recognizes compensation expense for performance-based awards ratably over the expected vesting period based on the grant date fair value when it is deemed probable, for accounting purposes, that the performance criteria will be achieved. The expected vesting period may be deemed to be shorter than the four-year term. As of June 30, 2017, certain performance-based awards were not considered probable of vesting for accounting purposes and no compensation expense has been recognized with regard to these awards. If these awards are later determined to be probable of vesting, cumulative compensation expense would be recorded at that time and amortization would continue over the remaining expected vesting period.

Market-based awards granted in 2016 entitle employees to vest in a fixed number of shares when the three-year trailing total return on the Company's common stock exceeds the corresponding total returns of various quartiles of an index consisting of designated peer companies during defined measurement periods. Market-based awards granted in fiscal 2015 and 2016 entitle employees to vest in a fixed number of shares when the three-year trailing total return on the Company's common stock exceeds the corresponding total returns of various quartiles of companies comprising the SIG Exploration and Production Index (NASDAQ EPX) during defined measurement periods. The fair value and expected vesting period of these awards were determined using a Monte Carlo simulation based on the historical volatility of the Company's total return compared to the historical volatilities of the other companies in the index. Vesting of market-based awards granted in fiscal 2017 is based on the Company's total common stock return compared to a peer group of sixteen companies in our industry with comparable market capitalizations. During the fiscal year ended June 30, 2017, we granted market-based awards with grant date fair values ranging from $3.42 to $5.62 per share, all with an expected vesting period of 2.83 years, based on the various quartiles of comparable market performance. During the fiscal year ended June 30, 2016, we granted market-based awards with fair values ranging from $2.93 to $5.07, all with an expected vesting period of 3.83 years, based on the various quartiles of comparative market performance. During the fiscal year ended June 30, 2015, we granted market-based awards with fair values ranging from $4.26 to $8.40 with expected vesting periods of 2.55 to 3.30 years, based on the various quartiles of comparative market performance. Compensation expense for market-based awards is recognized over the expected vesting period using the straight-line method, so long as the award holder remains an employee of the Company. Total compensation expense is based on the fair value of the awards at the date of grant and is independent of vesting or expiration of the awards, except for termination of service.

Unvested Restricted Stock awards at June 30, 2017 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Service-based awards	217,922	$ 7.03
Performance-based awards	54,475	5.67
Market-based awards	119,227	4.97
Unvested Restricted Stock at June 30, 2017	391,624	$ 6.22

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2017:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2017	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2016	406,848	$ 6.74	$ —	
Service-based awards granted	86,563	7.02		
Performance-based awards granted	54,475	5.67		
Market-based awards granted	54,475	5.44		
Vested	(210,737)	7.22		
Unvested Restricted Stock at June 30, 2017	391,624	$ 6.22	$ 1,648,297	2.0

During the years ended June 30, 2017, 2016, and 2015, there were 210,737, 86,719, and 91,306 shares of Restricted Stock that vested with a total grant date fair value of $1,520,569, $757,229, and $766,970, respectively.

Unvested Contingent Restricted Stock awards at June 30, 2017 consisted of the following:

Award Type	Number of Contingent Restricted Shares	Weighted Average Grant-Date Fair Value
Performance-based awards	39,403	$ 7.02
Market-based awards	73,867	3.37
Unvested Contingent Restricted Stock at June 30, 2017	113,270	$ 4.64

The following table summarizes Contingent Restricted Stock activity:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2017 (1)	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2016	91,172	$ 5.21		
Performance-based awards granted	27,237	5.67		
Market-based awards granted	27,237	3.42		
Vested	(32,376)	$ 6.09		
Unvested Contingent Restricted Stock at June 30, 2017	113,270	$ 4.64	$ 121,668	2.1

(1) Excludes $276,702 of potential future compensation expense for 39,403 shares of performance-based awards for which vesting is not considered probable at this time for accounting purposes.

Stock-based Compensation Expense

For the years ended June 30, 2017, 2016, and 2015, we recognized stock-based compensation expense related to Restricted Stock and Contingent Restricted Stock grants of $1,180,618, $1,809,548, and $943,653, respectively. Expense for June 30, 2016 includes $59,339 of stock-based compensation that was incurred in a restructuring.

Note 12 – Supplemental Disclosure of Cash Flow Information

Our supplemental disclosures of cash flow information for the years ended June 30, 2017, 2016, and 2015 are as follows:

	June 30,		
	2017	2016	2015
Income taxes paid	$ 1,495,377	$ 540,000	$ 220,000
Income tax refunds	—	1,556,999	331,733
Non-cash transactions:			
Increase (decrease) in accrued purchases of property and equipment	(3,076,245)	(2,250,048)	5,422,566
Deferred loan costs charged to oil and gas property costs	—	107,196	—
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	471,864	140,151	576,039
Mengel working interest acquired in Delhi Field litigation settlement	—	596,500	—
Royalty rights acquired through non-monetary exchange of patent and trademark assets	—	108,512	—
Previously acquired Company shares swapped by holders to pay stock option exercise price	$ 77,156	$ 76,500	$ —
Accrued purchases of treasury stock	—	(170,283)	170,283

Note 13 – Income Taxes

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

There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2017, 2016 and 2015. We believe that we have appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's tax returns are open to audit under the statute of limitations for the years ending June 30, 2014 through June 30, 2016 for federal tax purposes and for the years ended June 30, 2013 through June 30, 2016 for state tax purposes.

The components of our income tax provision are as follows:

	June 30, 2017	June 30, 2016	June 30, 2015
Current:			
Federal	$ 168,152	$ 8,731,290	$ 1,413,296
State	581,593	264,254	608,436
Total current income tax provision	749,745	8,995,544	2,021,732
Deferred:			
Federal	3,880,522	541,891	1,282,059
State	210,397	33,344	140,430
Total deferred income tax provision	4,090,919	575,235	1,422,489
	$ 4,840,664	$ 9,570,779	$ 3,444,221

The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate, currently 34%, to the income tax provision in our financial statements. Our effective tax rate for 2017 exceeded the statutory rate primarily as a result of state of Louisiana income taxes, partly offset by depletion in excess of basis. The effective tax rate for 2016 is less than the statutory rate primarily due to the benefit derived from statutory depletion in excess of tax basis and the Company had significant legal settlement and derivative gains that were not taxable in Louisiana. The effective tax rates for 2015 exceeded the statutory rate primarily due to state of Louisiana income taxes.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	June 30, 2017	% of Income Before Income Taxes	June 30, 2016	% of Income Before Income Taxes	June 30, 2015	% of Income Before Income Taxes
Income tax provision computed at the statutory federal rate	$ 4,380,892	34.0 %	$ 11,638,588	34.0 %	$ 2,868,267	34.0 %
Reconciling items:						
Depletion in excess of basis	(92,196)	(0.7)%	(2,242,620)	(6.6)%	—	— %
State income taxes, net of federal tax benefit	522,713	4.1 %	196,415	0.6 %	595,708	7.1 %
Permanent differences related to stock-based compensation	27,884	0.2 %	—	— %	—	— %
Other	1,371	— %	(21,604)	(0.1)%	(19,754)	(0.2)%
Income tax provision	$ 4,840,664	37.6 %	$ 9,570,779	27.9 %	$ 3,444,221	40.9 %

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Deferred tax assets and liabilities are classified as either current or noncurrent on the balance sheet based on the classification of the related asset or liability for financial reporting purposes. Deferred tax assets and liabilities not related to specific assets or liabilities on the financial statements are classified according to the expected reversal date of the temporary difference or the expected utilization date for tax attribute carryforwards.

	Asset (Liability)		
	June 30, 2017	June 30, 2016	June 30, 2015
Deferred tax assets:			
Non-qualified stock-based compensation	$ 367,159	$ 553,182	$ 173,647
Net operating loss carry-forwards	852,477	386,808	400,288
AMT credit carry-forward	110,564	—	701,254
Other	18,581	130,947	91,113
Gross deferred tax assets	1,348,781	1,070,937	1,366,302
Valuation allowance	(292,446)	(292,446)	(292,446)
Total deferred tax assets	1,056,335	778,491	1,073,856
Deferred tax liability:			
Oil and natural gas properties	(16,882,626)	(12,513,863)	(12,233,993)
Total deferred tax liability	(16,882,626)	(12,513,863)	(12,233,993)
Net deferred tax liability	$ (15,826,291)	$ (11,735,372)	$ (11,160,137)

The above assets and liabilities are present on the balance sheet as follows:

	June 30, 2017	June 30, 2016	June 30, 2015
Current deferred tax asset	$ —	$ 105,321	$ 82,414
Non-current deferred tax liability	15,826,291	11,840,693	11,242,551
Net liability	15,826,291	11,735,372	11,160,137

As the result of early adopting ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, at the beginning of this fiscal year current deferred tax assets have been netted together with noncurrent deferred income tax liabilities on the June 30, 2017 consolidated balance sheet. The prior years presented have not been retrospectively adjusted.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of June 30, 2017, we had a federal tax loss carryforward of approximately $1.2 million that we acquired through the reverse merger in May 2004. The majority of the tax loss carryforwards from the reverse merger expired without being utilized. We will be able to utilize a maximum of $0.3 million of these carryforwards in equal annual amounts of $39,648 through 2023 and the balance is not able to be utilized based on the provisions of IRC Section 382. We have recorded a valuation allowance for the portion of our net operating loss that is limited by IRC Section 382. During this fiscal year we generated a net operating loss of approximately $9.1 million in the State of Louisiana reflecting bonus depreciation tax deductions for our NGL plant, which was placed in service during fiscal 2017.

During fiscal 2016 we utilized the remaining amount of $25.3 million of net operating losses ("NOL's") created primarily from tax deductions in excess of book deductions related to the exercise of non-qualified stock options and incentive warrants in fiscal 2014. NOL's related to such stock-based awards had not affected our future tax provision for financial reporting purposes, nor had it been recognized as a deferred tax asset for these future benefits. In fiscal 2016 and 2015, we recognized a tax benefit for utilization of these NOL's to offset cash taxes that would otherwise have been payable as an increase in additional paid in capital, in amounts of $9,650,657 and $1,633,946 respectively.

In late September 2015, we received a $1.5 million refund payment of cash taxes paid to the State of Louisiana over a three-year period ended June 30, 2014. We also received $57,467 from the State of Louisiana for interest on the refund and recorded it as a reduction of current income tax expense. This carryback of tax losses resulted from the exercise of stock options and incentive warrants in fiscal 2014 and, accordingly, we recognized this benefit as an increase in additional paid-in capital for financial reporting purposes. This carryback utilized approximately $19.1 million of an estimated $24.2 million net loss for state tax purposes. The remaining balance of this net loss carryforward in Louisiana was utilized in the tax return for the year ended June 30, 2015.

In addition, as of June 30, 2017, the Company had an estimated carryforward of percentage depletion in excess of basis of approximately $7.2 million. These future deductions are limited to 65% of taxable income in any period.

Note 14 – Related Party Transactions

On June 30, 2011, we entered into a Technology Assignment Agreement with the Company’s Senior Vice President of Operations to acquire exclusive, perpetual, non-cancelable rights to the patented artificial lift technology he developed while employed by the Company. Under the agreement, he was paid a fee when the technology was employed. For the years ended June 30, 2016 and 2015, we made payments of $0 and $26,579, respectively, under the agreement, while he served as an officer of the Company. Our obligations with respect to this agreement were terminated in December 2015 in connection with the transfer of our artificial lift technology operations to WLI discussed in Note 7.

Note 15 – Net Income Per Share

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

	June 30,		
	2017	**2016**	**2015**
Numerator			
Net income attributable to common shareholders	$ 6,790,883	$ 23,986,060	$ 4,317,555
Denominator			
Weighted average number of common shares – Basic	33,034,480	32,810,375	32,817,456
Effect of dilutive securities:			
Contingent restricted stock grants	53,546	9,378	4,422
Stock Options	22,534	41,478	102,140
Total weighted average dilutive securities	76,080	50,856	106,562
Weighted average number of common shares and dilutive potential common shares used in diluted EPS	33,110,560	32,861,231	32,924,018
Net income per common share – Basic	$ 0.21	$ 0.73	$ 0.13
Net income per common share – Diluted	$ 0.21	$ 0.73	$ 0.13

The following were reflected in the calculation of diluted earnings per share as of June 30, 2017:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2017
Contingent Restricted Stock grants	$ —	113,270

The following were reflected in the calculation of diluted earnings per share as of June 30, 2016:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2016
Contingent Restricted Stock grants	$ —	91,172
Stock Options	2.19	35,231
Total	$ 0.61	126,403

The following were reflected in the calculation of diluted earnings per share as of June 30, 2015:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2015
Contingent Restricted Stock grants	$ —	56,286
Stock Options	2.50	91,061
Total	$ 1.55	147,347

Note 16 – Credit Agreements

Senior Secured Credit Agreement

On April 11, 2016, the Company entered into a new three-year, senior secured reserve-based credit facility ("Facility") in an amount up to $50 million. The Facility replaces the Company's previous unsecured credit facility which expired in April 2016. The initial borrowing base under the Facility was set at $10,000,000 and the Company has no outstanding borrowings.

Borrowings from the Facility may be used for the acquisition and development of oil and gas properties and for letters of credit and other general corporate purposes. Availability of borrowings under the Facility is subject to semi-annual borrowing base redeterminations.

The Facility included a placement fee of 0.50% on the initial borrowing base, amounting to $50,000, and carries a commitment fee of 0.25% per annum on the undrawn portion of the borrowing base. Any borrowings under the Facility will bear interest, at the Company's option, at either Libor plus 2.75% or the Prime Rate, as defined, plus 1.00%. The Facility contains financial covenants including a requirement that the Company maintain, as of the last day of each fiscal quarter, (a) a maximum total leverage ratio of not more than 3.00 to 1.00, (b) a debt service coverage ratio of not less than 1.10 to 1.00, and (c) a consolidated tangible net worth of not less than $40 million, all as defined under the Facility.

In connection with this agreement, the Company incurred $168,972 of debt issuance costs. Such costs were capitalized in Other Assets and are being amortized to expense over the term of the facility. The unamortized balance in debt issuance costs related to the Facility was $98,468 as of June 30, 2017.

Unsecured Revolving Credit Agreement

On February 29, 2012, the Company and a commercial bank entered into an unsecured credit agreement with a four year term. The agreement had provided $5 million of availability, which the Company never utilized. The original expiration date was extended to April 29, 2016. In connection with this agreement, the Company had incurred $179,468 of debt issuance costs. Such costs had been capitalized in Other Assets and have been completely amortized to expense in the prior fiscal year.

Note 17 – Delhi Field Litigation Settlement

On June 24, 2016, we entered into a settlement agreement with Denbury Resources, Inc., operator of the Delhi field, to resolve all outstanding disputes and claims between the parties, including litigation between Evolution and Denbury with respect to the Delhi field in northeastern Louisiana. The litigation between the parties has been dismissed by the Court with prejudice. In connection with this settlement, the Company recognized a $28.1 million settlement gain consisting of a $27.5 million cash payment made by Denbury to Evolution, together with its conveyance to Evolution of a 23.9% working interest in the Mengel Sand Interval, a separate interval within the boundaries of the Delhi field which is not currently producing and for which we estimated a Level 2 fair value of $596,500. As part of the settlement, Evolution conveyed a 0.2226% (.002226) overriding royalty interest in the Delhi field to Denbury.

Note 18 – Commitments and Contingencies

On December 3, 2013, our wholly owned subsidiary, NGS Sub Corp., was served with a lawsuit filed in the 8th Judicial District Court of Winn Parish, Louisiana by Cecil M. Brooks and Brandon Hawkins, residents of Louisiana, alleging that in 2006 a former subsidiary of NGS Sub Corp. improperly disposed of water from an off-lease well into a well located on the plaintiffs' land in Winn Parish. The plaintiffs requested monetary damages and other relief. The plaintiffs subsequently filed an amended petition joining the Company as defendants in its capacity as parent company of NGS Sub Corp. NGS Sub Corp. divested its ownership of the property in question along with its ownership of the subsidiary in 2008 to a third party. NGS Sub Corp. and the Company have denied the plaintiffs' claims. The district court dismissed the claim of Brooks against NGS Sub Corp. and the Company because Brooks purchased the land where the well is located subsequent to the divestiture of the property by NGS Sub. Corp. The claim of Hawkins is still being defended. Trial is currently scheduled for March 2018. We will continue to vigorously defend the claims and after consultation with our legal counsel, we consider the likelihood of a material loss to the Company in this matter to be remote.

Lease Commitments. During the year ended June 30, 2017, our previous lease for office space ended and we moved into smaller office space and entered into a non-cancelable lease that expires on May 31, 2019. Future minimum lease commitments as of June 30, 2017 under our office lease are as follows:

For the fiscal year ended June 30,	
2018	$ 73,073
2019	66,984
Total	$ 140,057

Rent expense for the years ended June 30, 2017, 2016, and 2015 was $80,472, $182,626, and $175,103, respectively.

Note 19 – Concentrations of Credit Risk

Major Customers. Historically we market all of our oil and natural gas production from the properties we operate. We do not currently market our share of crude oil and NGL production from Delhi. Although we have the right to take our working interest production at Delhi in-kind, we are currently selling our production under the Delhi operator's agreement with Plains Marketing L.P. and American Midstream for the sale of our oil and NGL's, respectively at the field. The majority of our operated gas, oil and condensate production is sold to 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 of our net oil and natural gas revenues during the years ended June 30, 2017, 2016, and 2015. The loss of our purchasers at the Delhi field or disruption to pipeline transportation from the field could adversely affect our net realized pricing and potentially our near-term production levels.

	Year Ended June 30,		
Customers	2017	2016	2015
Plains Marketing L.P. (Oil sales from Delhi)	97%	99%	99%
American Midstream Gas Solutions (NGL sales from Delhi)	3%	—%	—%
All others	—%	1%	1%
Total	100%	100%	100%

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. Our concentration of customers in this industry may impact our overall credit risk.

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

Note 20 – Retirement Plan

We have a Company sponsored 401(k) Retirement Plan ("Plan") which covers all full-time employees. We currently match 100% of employees' contributions to the Plan, to a maximum of the first 6% of each participant's eligible compensation, with Company cash contributions fully vested when made. Our matching contributions to the Plan totaled $53,113, $88,348, and $85,676 for the years ended June 30, 2017, 2016, and 2015, respectively.

Note 21 – Derivatives

In June 2015, the Company began using derivative instruments to reduce its exposure to crude oil price volatility for a substantial portion of its near-term forecasted production. The Company's objectives for this program were to achieve a more predictable level of cash flows to support the Company's capital expenditure program and to provide better financial visibility for the payment of dividends on common stock. The Company uses both fixed price swap agreements and costless collars to manage its exposure to crude oil price risk. While these derivative instruments are intended to limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not intend to enter into derivative instruments for speculative or trading purposes.

The Company accounts for derivatives under the provisions of ASC 815 *Derivatives and Hedgin*g ("ASC 815") under which the Company records the fair value of the instruments on the balance sheet at each reporting date, with changes in fair value recognized in income. Given cost and complexity considerations, the Company did not elect to use cash flow hedge accounting provided under ASC 815. Under cash flow hedge accounting, the effective portion of the change in fair value of the derivative instruments would be deferred in other comprehensive income and not recognized in earnings until the underlying hedged item impacts earnings.

These derivative instruments can result in both fair value asset and liability positions held with each counterparty. These positions are offset to a single net fair value asset or liability at the end of each reporting period. The Company nets its fair value amounts of derivative instruments executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. At June 30, 2017, the Company had no derivative asset or liability positions. At June 30, 2016, the Company held a derivative instrument net asset position with its counterparty that had a fair value of $14,132.

The Company monitors the credit rating of its counterparties and believes it does not have significant credit risk. Accordingly, we do not currently require our counterparties to post collateral to support the net asset positions of our derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments.

For the year ended June 30, 2017, the Company recorded in the consolidated statement of operations a gain on derivative instruments of $29,758 consisting of a realized gain of $43,890 on settled derivatives and an unrealized loss of $14,132 on unsettled derivatives. For the year ended June 30, 2016, the Company recorded in the consolidated statement of operations a gain on derivative instruments of $3,439,229 which included a realized gain of $3,315,123 on settled derivatives and an unrealized gain of $124,106 on unsettled derivatives. For the year ended June 30, 2015, the Company recorded in the consolidated statement of operations a net unrealized loss on unsettled derivatives of $109,974.

Note 22 – Fair Value Measurement

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

The three levels are defined as follows:

Level 1—Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2—Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3—Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair Value of Derivative Instruments. At June 30, 2017, the Company had no derivative instruments and, accordingly, there were no derivative assets and liabilities presented in the year end balance sheet. The following table summarizes the location and amounts of the Company's assets and liabilities measured at fair value on a recurring basis as presented in the June 30, 2016 consolidated balance sheet. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	June 30, 2016		
Asset (Liability)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the Consolidated Balance Sheet
Current derivative assets	$ 45,263	$ (31,131)	$ 14,132
Current derivative liabilities	(31,131)	31,131	—
Total	$ 14,132	$ —	$ 14,132

The fair values of the Company's derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors. The fair values are also compared to the values provided by the counterparty for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities. To date, adjustments for credit quality have not had a material impact on the fair values.

Note 23 – 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 related to 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. Exploration and development costs also include amounts incurred due to the recognition of asset retirement obligations of $471,864, $140,151 and $576,039 during the years ended June 30, 2017, 2016, and 2015, respectively.

	For the Years Ended June 30,		
	2017	2016	2015
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$ —	$ —	$ —
Unproved property (a)	—	596,500	—
Exploration costs	—	—	—
Development costs	7,554,579	19,093,200	10,975,637
Total costs incurred for oil and natural gas activities	$ 7,554,579	$ 19,689,700	$ 10,975,637

(a) As described in Note 17 — Delhi Field Litigation Settlement, we received a 23.9% working interest in the non-producing Mengel Interval with an estimated fair value of $596,500. This cost is included in properties subject to amortization.

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of the net proved oil and natural gas reserves of our oil and gas properties located entirely within the United States of America are based on evaluations prepared by third-party reservoir engineers. Reserves volumes and values were determined under the method prescribed by the SEC for our fiscal years ended June 30, 2017, 2016, and 2015, which requires the application of the previous 12 months unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected life of the property, when estimating whether reserves quantities are economical to produce.

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

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

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
Proved developed and undeveloped reserves:				
June 30, 2014	10,526,344	2,278,688	2,906,863	13,289,510
Revisions of previous estimates (a)	(64,074)	156,195	(2,894,703)	(390,330)
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(450,294)	(1,288)	(7,221)	(452,786)
June 30, 2015	10,011,976	2,433,595	4,939	12,446,394
Revisions of previous estimates (b)	(765,385)	(198,233)	(3,319)	(964,171)
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(658,041)	(491)	(1,620)	(658,802)
June 30, 2016	8,588,550	2,234,871	—	10,823,421
Revisions of previous estimates (c)	508,123	(504,733)	16	3,390
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(724,523)	(43,907)	(16)	(768,433)
June 30, 2017	8,372,150	1,686,231	—	10,058,378
Proved developed reserves:				
June 30, 2014	7,858,224	32,164	481,042	7,970,562
June 30, 2015	7,347,231	1,572	4,939	7,349,626
June 30, 2016	7,168,249	—	—	7,168,249
June 30, 2017	6,617,389	1,332,803	—	7,950,192
Proved undeveloped reserves:				
June 30, 2014	2,668,120	2,246,524	2,425,821	5,318,948
June 30, 2015	2,664,745	2,432,023	—	5,096,768
June 30, 2016	1,420,301	2,234,871	—	3,655,172
June 30, 2017	1,754,761	353,425	—	2,108,186

(a) The 2,894,703 revision for natural gas in fiscal 2015 primarily reflects a 2,246,524 MCF reduction for the Delhi field NGL plant together with a 452,786 MCF revision at the Giddings Field for a well that was lost due to mechanical issues. The NGL plant revision resulted from a decision to change in the plant design to use the methane production internally to reduce field operating costs rather than selling it into the market. The 156,195 BBL positive natural gas liquids revision primarily reflects 185,499 BBL positive revision for better recovery from the redesigned NGL plant, partly offset by a 29,304 BBL negative revision from the lost Giddings well.

(b) The negative revision results primarily from the removal of proved undeveloped reserves in the far eastern part of the Delhi field, referred to as Test Site 6, which were deemed uneconomic under the lower SEC price case utilized at the end of the period.

(c) The positive crude oil revision resulted from better production performance during fiscal 2017 and the expectation of greater ultimate recoveries of oil from the Delhi field. The negative NGL revision results primarily from lower expectations for ultimate NGL recoveries from the plant based on production data after the plant commenced production.

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales and production and development costs have been estimated using, respectively, trailing 12 month unweighted arithmetic average first-day-of-the-month prices, and costs in effect at the end of the years indicated, as required by ASC 932, *Extractive Activities - Oil and Gas* ("ASC 932"). ASC 932 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing our proved oil and natural gas reserves assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to our proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company's proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of our proved reserves.

The standardized measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2017, 2016, and 2015 are as follows:

	For the Years Ended June 30,		
	2017	2016	2015
Future cash inflows	$ 425,094,736	$ 383,491,193	$ 807,030,282
Future production costs and severance taxes	(213,115,443)	(179,182,565)	(309,225,333)
Future development costs	(22,631,856)	(16,595,047)	(49,691,006)
Future income tax expenses	(47,055,551)	(45,713,438)	(123,888,665)
Future net cash flows	142,291,886	142,000,143	324,225,278
10% annual discount for estimated timing of cash flows	(59,354,333)	(64,042,824)	(165,028,739)
Standardized measure of discounted future net cash flows	$ 82,937,553	$ 77,957,319	$ 159,196,539

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

	Year Ended June 30,					
	2017		2016		2015	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$ 48.85	n/a	$ 42.91	n/a	$ 71.88	$ 3.44

There were no natural gas reserves in 2017 and 2016. The NGL prices utilized for future cash inflows were based on historical prices received, where available. For the Delhi NGL plant, we utilized historical prices for the expected mix and net pricing of natural gas liquid products.

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

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	For the Years Ended June 30,		
	2017	2016	2015
Balance, beginning of year	$ 77,957,319	$ 159,196,539	$ 226,077,672
Net changes in sales prices and production costs related to future production	19,821,288	(120,832,747)	(88,043,095)
Changes in estimated future development costs	(1,626,833)	74,991	(9,585,405)
Sales of oil and gas produced during the period, net of production costs	(23,649,087)	(17,079,363)	(18,538,016)
Net change due to extensions, discoveries, and improved recovery	—	—	—
Net change due to revisions in quantity estimates	(2,206,287)	(18,821,014)	(9,391,321)
Net change due to sales of minerals in place	—	—	—
Development costs incurred during the period	2,632,547	16,327,883	7,785,095
Accretion of discount	10,086,904	21,870,650	31,974,540
Net change in discounted income taxes	(5,045,279)	36,598,239	34,157,767
Net changes in timing of production and other	4,966,981	622,141	(15,240,698)
Balance, end of year	$ 82,937,553	$ 77,957,319	$ 159,196,539

Note 24 – Selected Quarterly Financial Data (Unaudited)

The following table presents summarized quarterly financial information for the years ended June 30, 2017 and 2016:

2017	First	Second	Third	Fourth
Revenues	$ 7,593,940	$ 8,529,817	$ 9,525,437	$ 8,835,702
Operating income	2,727,593	3,675,381	3,893,236	2,583,912
Net income available to common shareholders	$ 563,345	$ 2,307,634	$ 2,419,143	$ 1,500,761
Basic and diluted net income per share	$ 0.02	$ 0.07	$ 0.07	$ 0.05
Dividends per share declared and paid in the quarter	$ 0.05	$ 0.065	$ 0.070	$ 0.070

2016	First	Second (1)	Third	Fourth (2)
Revenues	$ 7,379,406	$ 6,622,927	$ 5,106,735	$ 7,240,434
Operating income (loss)	1,846,498	(454,987)	(681,147)	954,823
Net income (loss) available to common shareholders	$ 2,923,652	$ 654,697	$ (298,183)	$ 20,705,894
Basic and diluted net income (loss) per share	$ 0.09	$ 0.02	$ (0.01)	$ 0.63
Dividends per share declared and paid in the quarter	$ 0.05	$ 0.05	$ 0.05	$ 0.05

(1) Includes $1.3 million restructuring charge.

(2) Includes gain on settlement of Delhi field litigation of $28.1 million.

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 Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that the information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

Management's Report on Internal Control Over Financial Reporting

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

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company's internal control over financial reporting based on criteria established in the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2017.

The effectiveness of our internal control over financial reporting at June 30, 2017 has been audited by Hein & Associates LLP, the independent registered public accounting firm that also audited our financial statements. Their report is included in *Item 8. "Financial Statements"* of this Annual Report on form 10-K under the heading Report of Independent Registered Public Accounting Firm on internal control over financial reporting.

Changes in Internal Control Over Financial Reporting

There has been no change in the Company's internal control over financial reporting during the fourth quarter ended June 30, 2017 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 2017 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 2017 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 2017 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 2017 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 2017 fiscal year.

PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. **Financial Statements.**

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

   Report of Independent Registered Public Accounting Firm

   Consolidated Balance Sheets

   Consolidated Statements of Operations

   Consolidated Statements of Cash Flows

   Consolidated Statements of Stockholders' Equity

   Notes to the Consolidated Financial Statements

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

   None.

3. **Exhibits**

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

GLOSSARY OF SELECTED PETROLEUM TERMS

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

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

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

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

"BOPD." Barrels of oil per day.

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

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

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

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

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

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

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

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

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

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

"MBO." One thousand barrels of oil

"MBOE." One thousand barrels of oil equivalent.

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

"MMBOE." One million barrels of oil equivalent.

"MMBTU." One million British thermal units.

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

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

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

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

"NYMEX." New York Mercantile Exchange.

"OOIP." Original Oil in Place. An estimate of the barrels originally contained in a reservoir before any production therefrom.

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

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

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

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

“Possible Reserves.” Additional unproved reserves that analysis of geological and engineering data suggests are less likely to be recoverable than Probable Reserves, but have at least a ten percent probability of being recovered.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"SWIW." Salt water injection well.

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

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

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

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

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	
Date: September 15, 2017	By:	/s/ RANDALL D. KEYS Randall D. Keys *President and Chief Executive Officer* *(Principal Executive Officer)*

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 15, 2017	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 15, 2017	/s/ RANDALL D. KEYS Randall D. Keys	President and Chief Executive Officer (Principal Executive Officer)
September 15, 2017	/s/ DAVID JOE David Joe	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
September 15, 2017	/s/ RODERICK SCHULTZ Roderick Schultz	Chief Accounting Officer (Principal Accounting Officer)
September 15, 2017	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Independent Director
September 15, 2017	/s/ GENE STOEVER Gene Stoever	Director
September 15, 2017	/s/ WILLIAM DOZIER William Dozier	Director
September 15, 2017	/s/ KELLY W. LOYD Kelly W. Loyd	Director

Table of Contents

INDEX OF EXHIBITS

MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
3.1	Articles of Incorporation (previously filed as an exhibit to Form 8-K on February 7, 2002)
3.2	Certificate of Amendment to Articles of Incorporation (previously filed as an exhibit to 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	Certificate of Designation of Rights and Preferences for 8.5% Series A Cumulative Preferred Stock (previously filed as an exhibit to Form 8-K on June 29, 2011)
3.5	Bylaws (previously filed as an exhibit to Form 8-K on February 7, 2002)
3.6	Amended Bylaws (previously filed as Exhibit 2.1 to Form 10KSB on March 31, 2004)
4.1	Specimen form of the Company's Common Stock Certificate (previously filed as an exhibit to Form S-3 on June 19, 2013)
4.2	Specimen form of the Company's 8.5% Series A Cumulative Preferred Stock Certificate (previously filed as an exhibit to Form 8-A on June 29, 2011)
4.3	2004 Stock Plan (previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14C on August 9, 2004)
4.4	Amended and Restated 2004 Stock Plan, adopted December 4, 2007 (previously filed as Annex A to the Company's Definitive Information Statement on Schedule 14A on October 29, 2007)
4.5	Amendment to Amended and Restated 2004 Stock Plan, adopted December 5, 2011 (previously filed as Annex A to the Company's Definitive Information Statement on Schedule 14A on October 28, 2011)
4.6	Form of Stock Option Agreement for the Natural Gas Systems 2004 Stock Plan (previously filed as an exhibit to Form 8-K on April 8, 2005)
4.7	Form of Restricted Stock Agreement (previously filed as an exhibit to Form SC TO-I on May 15, 2009)
4.8	Form of Contingent Performance Stock Grant under the Amended and Restated 2004 Stock Plan (previously filed as an exhibit to Form 10-Q on November 7, 2014)
4.9	2016 Equity Incentive Plan (previously filed as an exhibit to the Company's Form 10-Q on February 8, 2017)
4.10	Majority Voting Policy for Directors (previously filed as an exhibit to the Company's Current Report on Form 8-K on October 31, 2012)
10.1	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)
10.2	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)
10.3	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)
10.4	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)
10.5	Settlement Agreement, dated June 24, 2016, by and among Denbury Onshore, LLC, Denbury Resources Inc., NGS Sub Corp., Tertiaire Resources Company, and the Company (previously filed as an exhibit to Form 10-K on September 9, 2016)
10.6	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)
10.7	Credit Agreement dated April 11, 2016 between Evolution Petroleum Corporation and MidFirst Bank (previously filed as an exhibit to Form 8-K on April 15, 2016)
14.1	Code of Business Conduct and Ethics (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 (filed herein)
23.2	Consent of DeGolyer and MacNaughton (filed herein)

EXHIBIT NUMBER	DESCRIPTION
31.1	Certification of Chief Executive Officer 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 President and Chief Financial Officer 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 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 President and Chief Financial Officer 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	The summary of DeGolyer and MacNaughton's Report as of June 30, 2017, on oil and gas reserves (SEC Case) dated August 31, 2017 and certificate of qualification (filed herein)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

Exhibit 21.1

List of Subsidiaries of Evolution Petroleum Corporation

Name of Subsidiary	Jurisdiction of Incorporation or Organization
NGS Sub Corp.	Delaware
NGS Technologies, Inc.	Delaware
Evolution Operating Co., Inc.	Texas
Tertiaire Resources Company	Texas
Evolution Petroleum OK, Inc.	Texas
NGS Resources, LLC (Subsidiary of NGS Technologies, Inc.)	Texas

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-193899 on Form S-3, Registration Statement No. 333-211338 on Form S-3, Registration Statement No. 333-152136 on Form S-8, Registration Statement No. 333-140182 on Form S-8, Registration Statement No. 333-183746 on Form S-8, and Registration Statement No. 333-216098 on Form S-8 of Evolution Petroleum Corporation of our report dated September 15, 2017, relating to the consolidated financial statements of Evolution Petroleum Corporation (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the effectiveness of internal control over financial reporting) of Evolution Petroleum Corporation, appearing in this Annual Report on Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2017.

/s/ Hein & Associates LLP

Hein & Associates LLP
Houston, Texas

September 15, 2017

EXHIBIT 23.2

DEGOLYER AND MACNAUGHTON

500 I SPRING ALLEY ROAD SUITE 800 EAST

DALLAS, TEXAS 75244

September 11, 2017

Evolution Petroleum Corporation 1155 Dairy Ashford
Suite 425
Houston, Texas 77079

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our letter report dated August 31, 2017, and to the inclusion of information taken from our "Report as of June 30, 2017 on Reserves and Revenue of Certain Properties owned by Evolution Petroleum Corporation" in the sections Business Strategy-Delhi Field - Enhanced Oil Recovery - Onshore Louisiana, Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in the Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2017. We further consent to the incorporation by reference of information in the Form 10-K, in the Evolution Petroleum Corporation Registration Statement No. 333-152136 on Form S-8, Registration Statement No. 333-140182 on Form S-8, Registration Statement No. 333-183746 on Form S-8, Registration Statement No. 333-216098 on Form S-8, Registration Statement No. 333-211338 on Form S-3, and Registration Statement No. 333-193899 on Form S-3.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

EXHIBIT 31.1

CERTIFICATION

I, Randall D. Keys, President and Chief Executive Officer of Evolution Petroleum Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: September 15, 2017

/s/ RANDALL D. KEYS
Randall D. Keys
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, David Joe, Chief Financial Officer of Evolution Petroleum Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: September 15, 2017

/s/ DAVID JOE
David Joe
Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

The undersigned, Randall D. Keys, President and Chief Executive Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2017 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has executed this certification as of September 15, 2017.

/s/ RANDALL D. KEYS
Randall D. Keys
President and Chief
Executive *Officer*

A signed original of this written statement require d by Section 906 has been provided to Evolution Petroleum Corporation and will be retained by Evolution Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certificate is being furnished to the Securities and Exchange Commission as an exhibit to this Form 10-K and shall not be considered filed as part of the Form 10-K.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, David Joe, Chief Financial Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2017 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has executed this certification as of September 15, 2017.

/s/ DAVID JOE
David Joe
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Evolution Petroleum Corporation and will be retained by Evolution Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certificate is being furnished to the Securities and Exchange Commission as an exhibit to this Form 10-K and shall not be considered filed as part of the Form 10-K.

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

August 31, 2017

Evolution Petroleum Corporation
1155 Dairy Ashford, #425
Houston, Texas 77079

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved, probable, and possible oil, condensate, natural gas liquids (NGL), and gas reserves, as of June 30, 2017, of certain properties in which Evolution Petroleum Corporation and its subsidiaries (collectively referred to herein as Evolution) have represented that they own an interest. This evaluation was completed on August 31, 2017. The properties evaluated consist of working and royalty interests in the Delhi field located in Franklin, Madison, and Richland Parishes, Louisiana. Evolution has represented that these properties account for 100 percent of its proved reserves as of June 30, 2017. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with the guidelines specified in Item 1202 (a)(8) of Regulation S-K, and is to be used for inclusion in certain SEC filings by Evolution.

Estimates of reserves included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after June 30, 2017. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Evolution after deducting all interests owned by others.

Values of proved, probable, and possible reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production and ad valorem taxes, operating expenses, and capital and abandonment costs from the future gross revenue. Operating expenses include field operating expenses, carbon dioxide purchase expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at 10 percent compounded annually over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of oil, condensate, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this report were obtained from Evolution, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Evolution with respect to property interests evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. It was not considered necessary to make a field examination of the physical condition and operation of the properties.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Evolution, and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved, probable, or possible.

The proved, probable, and possible oil, condensate, and gas reserves estimated for the evaluated interests are located in the Holt-Bryant reservoir in the Delhi field. This reservoir was originally discovered in 1944, produced under primary means until unitized for water injection in 1953, and was purchased by Denbury Resources (Denbury) in 2006 in order to initiate a carbon dioxide injection program. Average depth is 3,235 feet subsea. The Delhi Holt-Bryant Unit area is 13,636 acres, and the reservoir area is approximately

6,189 acres. Denbury began carbon dioxide injection in 3 patterns in November 2009 and has since expanded to 15 patterns, which have all seen production response to injection.

The volumetric method was used to estimate the original oil in place (OOIP). Structure maps were utilized to delineate each reservoir, and isopach maps were utilized to estimate reservoir volume. Electrical logs, radioactivity logs, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. Cumulative recovery from the Delhi Holt-Bryant Unit prior to carbon dioxide injection was about 195 million barrels. Estimates of ultimate recovery resulting from carbon dioxide injection in the Holt-Bryant reservoir were obtained after applying recovery factors to the current carbon dioxide flood area OOIP (flood area OOIP) of 325.1 million barrels. This recovery factor was based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. Oil production response to the carbon dioxide injection was observed in March 2010. Based on the production response from a number of producers, and noting the amount of carbon dioxide injection to date, a total recovery factor for proved reserves was estimated to be about 14.3 percent of the flood area OOIP, incremental probable reserves about 5.1 percent of the flood area OOIP, and incremental possible reserves about 3.1 percent of the flood area OOIP. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production.

Future oil and gas producing rates estimated for this report are based on production rates considering the most recent data available. The rates used for future production are estimated to be within the capacity of a well or reservoir to produce.

In the preparation of this report, as of June 30, 2017, production data through June 2017 were available. Gross production through June 30, 2017, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves. Data available from wells drilled through June 2017 were used in this report.

Evolution has represented that it owns an interest in the Delhi Plant that began operation in December 2016 and that the Delhi Plant processes gas from the Delhi Holt-Bryant Unit to produce NGL and methane. The methane is used for fuel in the field and for plant operations. The NGL yield through the plant was provided by Evolution. This NGL yield was used to estimate the NGL reserves attributable to the leases in the Delhi Holt-Bryant Unit.

Gas quantities estimated herein are expressed as separator gas and sales gas. Separator gas is the gas remaining after field separation but prior to gas processing and shrinkage for fuel use or flare. Sales gas is defined as that portion of the separator gas to be delivered into a gas pipeline for sale after field separation, processing, fuel use, and flare. All gas quantities are expressed at a temperature base of 60 degrees Fahrenheit and at a pressure base of 15.025 pounds per square inch absolute. Gas quantities included in this report are expressed in thousands of cubic feet (Mcf). All of the produced gas is consumed as fuel or lost in processing, so the sales gas reserves are zero.

Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation and are expressed in terms of barrels (bbl) representing 42 United States gallons per barrel. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity. NGL reserves are those attributed to the leasehold interests according to processing agreements.

Definition of Reserves

Petroleum reserves included in this report are classified by degree of proof as proved, probable, or possible. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *Proved oil and gas reserves* - Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> (i) The area of the reservoir considered as proved includes:
> (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Probable reserves - Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (iv) and (vi) of the definition of possible reserves.

Possible reserves - Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (iii) of the proved oil and gas reserves definition, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4-10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable and possible reserves in this report have not been adjusted in consideration of these additional risks and therefore are not comparable with estimates of proved reserves.

Primary Economic Assumptions

Revenue values in this report were estimated using the initial prices and costs specified by Evolution. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The assumptions used for estimating future prices and expenses are as follows:

Oil and Condensate Prices

An oil and condensate price differential was estimated from data provided by Evolution. The oil and condensate price was calculated by applying this differential to a West Texas Intermediate (WTI) crude oil price of $48.85 per barrel and was held constant over the lives of the properties. The WTI price of $48.85 is the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period prior to June 30, 2017. The volume-weighted average price attributable to the proved reserves over the lives of the properties was $46.65 per barrel.

NGL Prices

Evolution has represented that the NGL price was based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The volume-weighted average price attributable to the proved reserves over the lives of the properties was
$20.48 per barrel.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, capital costs, and abandonment costs, based on information provided by Evolution for current costs, were used for the lives of the properties with no increases in the future based on inflation. Future capital costs provided by Evolution were estimated using 2017 values and were not adjusted for inflation. Evolution has represented that the abandonment costs include site restoration and reclamation. No significant capital costs other than abandonment are expected after 2022.

Production and Ad Valorem Taxes

Production taxes were based on current state tax rates. Evolution has represented that the Delhi carbon dioxide flood has been qualified as a tertiary recovery project and that no oil and condensate production taxes will be charged until payout of investment and certain interest expenses from project revenue. Oil and condensate production taxes then revert to a 12.5-percent rate, which rate is held constant until average oil production per well drops below 25 barrels per day, and then reduced to 6.25 percent thereafter. Payout is not expected to occur prior to depletion, so no oil and condensate production taxes are included herein. Production taxes for NGL are included at $0.14 per barrel. Evolution has represented that no ad valorem taxes are charged to the Louisiana royalty owners, so no ad valorem taxes are included herein for the royalty interests.

Summary and Conclusions

The estimates of net proved, probable, and possible reserves attributable to Evolution from the properties evaluated, as of June 30, 2017, are summarized as follows, and expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Net Reserves		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved			
Developed Producing	6,617	1,333	0
Developed Non-Producing	0	0	0
Undeveloped	1,755	353	0
Total Proved	**8,372**	**1,686**	**0**
Probable			
Developed Producing	3,577	720	0
Developed Non-Producing	0	0	0
Undeveloped	808	163	0
Total Probable	**4,385**	**883**	**0**
Possible			
Developed Producing	2,373	478	0
Developed Non-Producing	0	0	0
Undeveloped	304	61	0
Total Possible	**2,677**	**539**	**0**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

The estimated future revenue to be derived from the production and sale of the estimated net proved, probable, and possible reserves, as of June 30, 2017, of the properties evaluated is summarized as follows, expressed in thousands of dollars (M$):

	Proved			
	Developed Producing (M$)	Developed Non-Producing (M$)	Undeveloped (M$)	Total Proved (M$)
Future Gross Revenue	335,997	0	89,098	425,095
Production Taxes	187	0	50	237
Ad Valorem Taxes	1,378	0	365	1,743
Operating Expenses	173,551	0	37,585	211,136
Capital Costs	2,580	0	14,155	16,735
Abandonment Costs	5,286	0	611	5,897
Future Net Revenue	153,015	0	36,332	189,347
Present Worth at 10 Percent	101,696	0	9,199	110,895

	Probable			
	Developed Producing (M$)	Developed Non-Producing (M$)	Undeveloped (M$)	Total Probable (M$)
Future Gross Revenue	181,643	0	40,996	222,639
Production Taxes	101	0	23	124
Ad Valorem Taxes	745	0	168	913
Operating Expenses	55,670	0	14,118	69,788
Capital Costs	0	0	0	0
Abandonment Costs	0	0	0	0
Future Net Revenue	125,127	0	26,687	151,814
Present Worth at 10 Percent	47,760	0	5,547	53,307

	Possible			
	Developed Producing (M$)	Developed Non-Producing (M$)	Undeveloped (M$)	Total Possible (M$)
Future Gross Revenue	120,511	0	15,413	135,924
Production Taxes	67	0	9	76
Ad Valorem Taxes	494	0	63	557
Operating Expenses	23,675	0	5,047	28,722
Capital Costs	0	0	0	0
Abandonment Costs	0	0	0	0
Future Net Revenue	96,275	0	10,294	106,569
Present Worth at 10 Percent	25,896	0	1,166	27,062

Notes:
1. Future income tax expenses were not taken into account in the preparation of these estimates.
2. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant’s ability to recover its oil, condensate, NGL, and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the June 30, 2017, estimated reserves.

In our opinion, the information relating to estimated proved, probable, and possible reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, Extractive Industries - Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the Financial Accounting Standards Board and Rules 4-10(a) (1)-(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (5), (8), and 1203(a) of Regulation S-K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Evolution. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Evolution. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Dennis W. Thompson, PE
Dennis W. Thompson, PE
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Dennis W. Thompson, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Evolution Petroleum Corporation dated August 31, 2017, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

2. That I attended Eastern New Mexico University, and that I graduated with a Bachelor of Science degree in Geology in the year 1973; that I earned a Master of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 38 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dennis W. Thompson, PE
Dennis W. Thompson, PE
Senior Vice President
DeGolyer and MacNaughton