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, 2019

☐ **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 (State or other jurisdiction of incorporation or organization)	**41-1781991** (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	Trading Symbol(s)	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	EPM	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: ☐ 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: ☐ 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: ☐

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: ☐

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 ☐	Accelerated filer ☒
Non-accelerated filer ☐	Smaller reporting company ☒
	Emerging growth company ☐

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. ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2018, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $6.75 on the NYSE American was $158,319,105.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 6, 2019, was 33,064,797.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2019 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
2019 ANNUAL REPORT ON FORM 10-K

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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.

FORWARD-LOOKING STATEMENTS

This Form 10-K and the information referenced herein contains 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 Part I, Item 1A, "Risk Factors" and elsewhere in this report and as also may be described from time to time in our future reports we file with the Securities and Exchange Commission. You should read such information in conjunction with our consolidated condensed financial statements and related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not currently perceive them to be material. Such factors could cause results to differ materially from our expectations.

Forward-looking statements speak only as of the date they are made, and we do not undertake to update these statements other than as required by law. You are advised, however, to review any further disclosures we make on related subjects in our periodic filings with the Securities and Exchange Commission.

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, a gas that can be found in naturally occurring reservoirs, typically associated with ancient volcanoes, and also is a major byproduct from manufacturing and power production also utilized in enhanced oil recovery through injection into an oil reservoir.

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

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

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

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

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

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

"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.

"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").

"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.

PART I

Item 1. Business

Note: *See Glossary of Selected Petroleum Industry Terms starting on page* iii

General

Evolution Petroleum Corporation is an oil and gas company focused on delivering a sustainable dividend yield to its shareholders through the ownership, management and development of producing oil and gas properties. The Company's long-term goal is to build a diversified portfolio of oil and gas assets primarily through acquisition, while seeking opportunities to maintain and increase production through selective development, production enhancement and other exploitation efforts on its properties.

Our producing assets over the last three fiscal years consisted of our interests in the Delhi Holt-Bryant Unit in the Delhi field (the "Unit") in Northeast Louisiana, a CO_2 enhanced oil recovery project, and a de minimis overriding royalty interest retained in a past divestiture. We have a combined net revenue interest in the Unit of 26.2% comprised of 7.2% of overriding royalty interests that are in effect for the life of the Unit and mineral royalty interests and a 23.9% working interest with an associated 19.0% net revenue interest.

Significant Activity in Fiscal 2019

- Delhi proved oil equivalent reserves at June 30, 2019 were 9.0 MMBOE, a 4% decrease from the previous year. The Standardized Measure for proved reserves increased 7% to $127 million, reflecting a rise in realized commodity price from $54.71 to $58.50 per BOE. Our proved reserves consist of 85% crude oil and 15% natural gas liquids.
- Delhi probable** reserves at June 30, 2019 were 4.8 MMBOE, a 7% increase over the previous year. 87% of these reserves are incremental reserves associated with existing developed and producing locations. No additional capital investment is required beyond what is captured in proved reserves.
- Delhi possible** reserves at June 30, 2019 were 4.3 MMBOE, a 7% decrease over the previous year. 91% of these reserves are incremental reserves associated with existing developed and producing locations. No additional capital investment is required beyond what is captured in proved reserves.
- The twelve well infill program, consisting of ten producer wells and two CO_2 injector wells, was completed and on production during fiscal 2019, converting 536 MBOE of proved undeveloped to proved developed reserves.
- Capital expenditures for the six-well water curtain program and related infrastructure preceding the planned Delhi Phase V development is almost complete. The first pad commenced operations during fiscal 2019 and the second pad is expected to begin injections during our second quarter of fiscal 2020.

Our Reserves: Delhi Field - Enhanced Oil Recovery - Onshore Louisiana

Our independent petroleum engineering firm, DeGolyer & MacNaughton ("D&M"), assigned the estimated reserves net to our interests at Delhi as of June 30, 2019. We had 9.0 million bbls of proved oil equivalent reserves, with a Standardized Measure of $127 million, and PV-10* of $157 million. The following table summarizes the reserves assigned by D&M:

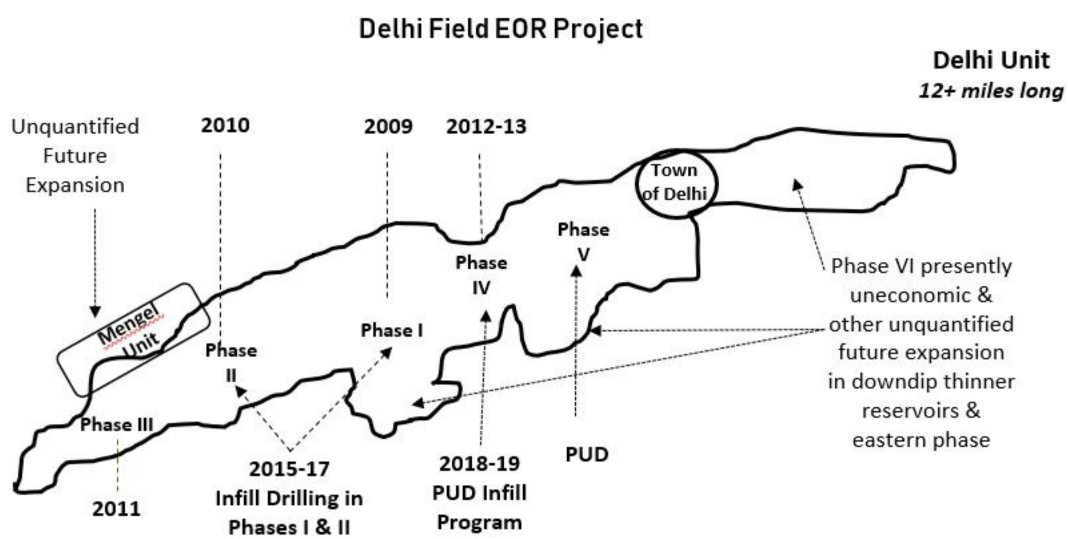
	Reserves as of June 30, 2019		
	Proved	Probable**	Possible**
Reserves MBOE	8,981	4,783	4,321
% Developed	82%	87%	91%
Liquids %	100%	100%	100%
Standardized Measure ($MM)	$ 127		
PV-10* ($MM)	$ 157		

* 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" below in *Item 1. Business* in this 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, 2019, which were $64.54 per barrel of oil and $23.83 per barrel of natural gas liquids ("NGL"). Probable and possible reserves are not recognized under GAAP nor is there a comparable GAAP measure for probable and possible reserves.

** With respect to the above reserve numbers, and references to probable and possible reserves throughout this document, 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 and there must be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserve estimates. Possible reserves are even less certain and there must be at least a 10% probability that the actual quantities recovered will equal or exceed the sum of proved, probable and possible reserve estimates. 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.

Development History of the Delhi Field - Enhanced Oil Recovery - Onshore Louisiana

Our working and royalty interests in the Delhi field are currently our primary 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 in the purchase and sale agreements. Since EOR production began in March 2010, the Unit has produced over 20 million bbls of oil.



After the May 2006 conveyance, Denbury Resources, Inc., as 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 gross 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 gross barrels of oil per day.

In June 2013, following an adverse 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 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, thus removing that area from the CO_2 flood.

Construction began on the NGL extraction plant in February 2015. During fiscal 2017, the NGL extraction plant was completed and began processing in December 2016. The 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 for the benefit and use 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 has resulted in operational benefits to the CO_2 flood. We have incurred a net capital cost of approximately $27 million for the plant, including capital upgrades since its commissioning.

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. 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 together with the consensus that Phase V project economics would be enhanced if it were implemented after completion of the NGL plant.

During fiscal 2019 the twelve well infill program, consisting of ten producing wells and two CO_2 injection wells was completed and on production. The program commenced in March 2018 to target productive oil zones in the developed areas of the field that were not being swept effectively by the CO_2 flood.

Also during the year, one pad of the six-well water curtain program was completed and commenced water injection during the second half of fiscal 2019. The project began late in fiscal 2017 after completion of the NGL plant with the drilling of one well followed by three wells in fiscal 2018. During fiscal 2019, we drilled the two remaining wells and proceeded with completions and injection line work. In fiscal 2020, we expect to incur approximately $0.6 million of net capital expenditures for completing the installation of the second three-well pad planned to begin injection in the second fiscal quarter.

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 liquids 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 that the actual quantities recovered will equal of exceed the proved plus probable reserve estimates. Possible reserves are even less certain and generally require only a 10% or greater probability of that actual quantities recovered will equal or exceed the sum of proved, probable and possible reserve estimates. 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.

Information About the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") and pre-tax PV-10 of Proved Reserves

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. Refer to the "*Reconciliation of PV-10 to the Standardized Measure of Discounted Future Net Cash Flows"* below.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2019

Our proved, probable and possible reserves at June 30, 2019, denominated in equivalent barrels using six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum engineer, DeGolyer and MacNaughton ("D&M") which was formed in 1936, employs over 180 petroleum engineers, geologists and other technical personnel, and operates domestically and around the world. 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 of the Delhi field. 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, 2019. For additional reserve information see *Note 20 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (Unaudited)* of the consolidated financial statements. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $61.62 per barrel of crude oil. The net price per barrel of natural gas liquids was $23.83, 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, 2019

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)*
PROVED			
Developed Producing (82% of Proved)	6,274	1,124	7,398
Undeveloped (18% of Proved)	1,342	241	1,583
TOTAL PROVED	7,616	1,365	8,981
Product Mix	85%	15%	100%
PROBABLE			
Developed Producing (87% of Probable)	3,516	630	4,146
Undeveloped (13% of Probable)	540	97	637
TOTAL PROBABLE	4,056	727	4,783
Product Mix	85%	15%	100%
POSSIBLE			
Developed Producing (91% of Possible)	3,323	596	3,919
Undeveloped (9% of Possible)	341	61	402
TOTAL POSSIBLE	3,664	657	4,321
Product Mix	85%	15%	100%

*Equivalent oil reserves are defined as six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio.

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 by Major Property

Proved reserves, MBOE	Delhi Field Proved Total MBOE
June 30, 2018	9,368
Production	(739)
Revisions	352
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2019	8,981

Reconciliation of Changes in Probable Reserves by Major Property

Probable reserves, MBOE	Delhi Field Probable Total MBOE
June 30, 2018	4,493
Revisions	290
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2019	4,783

Reconciliation of Changes in Possible Reserves by Major Property

Possible reserves, MBOE	Delhi Field Possible Total MBOE
June 30, 2018	4,570
Revisions	(249)
Sales of minerals in place	—
Improved recovery, extensions, and discoveries	—
June 30, 2019	4,321

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

The following table provides a reconciliation of PV-10 (Non-GAAP) of our proved properties to the Standardized Measure (GAAP) as shown in Note 20 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (Unaudited) of the consolidated financial statements.

	As of June 30, 2019	As of June 30, 2018
Estimated future net revenues	$297,102,269	$ 270,842,377
10% annual discount for estimated timing of future cash flows	140,489,586	124,798,505
Estimated future net revenues discounted at 10% (PV-10)	156,612,683	146,043,872
Estimated future income tax expenses discounted at 10%	(29,880,641)	(27,085,458)
Standardized Measure	**$126,732,042**	**$ 118,958,414**

Our primary proved producing assets as of June 30, 2019 and 2018 were our interests in the Delhi field.

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

Our policies regarding internal controls over reserves estimates require such estimates to be prepared by an independent petroleum engineering firm under the supervision of our Chairman of the Board and interim Chief Executive Officer and Senior Vice President of Engineering and Business Development, a professional petroleum engineer. Such reserves estimates are to be in compliance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC.

The reserves information in this filing is based on estimates prepared by DeGolyer and MacNaughton, our independent petroleum engineering firm, which was formed in 1936, employs over 180 petroleum engineers, geologists and other technical personnel, and operates domestically and around the world. 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 received a Bachelor of Science degree in petroleum engineering from the University of Texas in 1984, has over 35 years of experience in the energy industry and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Our Chairman of the Board and interim Chief Executive Officer 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 Senior Vice President of Engineering and Business Development received a Bachelor of Science degree in petroleum engineering from the University of Oklahoma in 1979 and has over 39 years of experience in the energy industry with upstream oil and gas companies. On July 10, 2019, Jason Brown was appointed President and Chief Executive Officer of the Company and Mr. Herlin remained as Chairman of the Board of Directors. Mr. Brown has over 20 years of experience in the energy industry and is a Registered Professional Engineer (Petroleum) in the State of Texas. He earned his B.S. degree in chemical engineering from the University of Tulsa and his M.B.A. from the Mendoza School of Business at the University of Notre Dame.

We provide our independent petroleum engineering firm with our property interests, production, current operating costs, current production prices and other information. This information is reviewed by our Senior Vice President of Engineering and Business Development and other members of management to ensure accuracy and completeness of the data prior to submission to this firm. The scope and results of our independent petroleum 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

Our Proved undeveloped reserves were 1,583 MBOE at June 30, 2019, with associated future development costs of approximately $8.6 million, which are associated with the Phase V development in the eastern portion of Delhi field.

During the year ended June 30, 2019 our proved undeveloped reserves changed as follows:

	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)
June 30, 2018	1,798	284	2,082
Revisions to previous estimates	7	30	37
Conversion to proved developed reserves	(463)	(73)	(536)
June 30, 2019	1,342	241	1,583

Oil and NGL reserves were revised upward 7 MBbls and 29 MBOE, respectively, reflecting improved existing well and NGL plant performance over the last year. The infill program, consisting of ten producer wells and two CO_2 injection wells, was completed during 2019 resulting in the conversion of 463 MBbls of oil and and 73 MBOE of NGLs from Proved undeveloped reserves to proved developed reserves. Since the project's inception in March 2018, our infill project net capital expenditures have totaled $4.6 million, of which $1.8 million was incurred during fiscal 2019.

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 were to 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 82% of total Proved reserves as of June 30, 2019. 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 field in February 2015. 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 fiscal 2015, we authorized the NGL plant project and from late in that fiscal year until January 2017 when production of NGLs began, we incurred $26.0 million of related capital expenditures. The NGL plant was completed in December 2016 and we converted approximately 1,377 MBOE of proved undeveloped reserves to proved developed reserves during fiscal 2017.

Since completion of the plant, we have resumed work that had been suspended in late 2014 and further deferred until the NGL recovery plant was complete. Cumulatively, we have spent $3.1 million as of June 30, 2019, including $1.6 million in fiscal 2019, on the six well water curtain program and related infrastructure required to precede the development of Phase V. As of June 30, 2019 we had drilled all the wells, including four gross wells during fiscal 2019, and commenced operations for one of the program's pads. The program was configured as two pads with each having two injector wells and one water source well. The second pad is expected to begin operations in the second fiscal quarter of 2020 and we expect to incur approximately $0.6 million net of capital expenditures to complete the program.

As of June 30, 2019, we have estimated total future net capital expenditures of approximately $8.6 million for remaining curtain infrastructure and development of Phase V in the eastern part of the field, which we expect to commence in our fourth fiscal quarter of 2020 based on our discussions with the operator. The timing of Phase V is dependent on the field operator's available funds and capital spending plans and priorities within its portfolio of properties.

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. We have been continuously developing the Delhi field and have spent over $47 million subsequent to reversion of our working interest in November 2014. 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 adverse 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, 2019, no proved, probable or possible reserves were attributed to (a) the area beneath the inhabited portion of the town of Delhi in the northeast and (b) the farthest east of the two remaining undeveloped sites in the eastern portion of the 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 out interests in the Mengel Sand, a separate interval within the Unit that is not currently producing, but has produced oil in the past.

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, 2019		Year Ended June 30, 2018		Year Ended June 30, 2017	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Crude oil (Bbls)	626,879	$ 65.05	651,931	$ 58.52	724,523	$ 46.31
Natural gas liquids (Bbls)	112,013	$ 21.87	93,366	$ 28.06	43,907	$ 16.01
Natural gas (Mcf)	459	$ 2.64	—	$ —	16	$ (0.25)
Average price per BOE*	738,968	$ 58.50	745,297	$ 54.71	768,433	$ 44.58
Production costs	**Amount**	**per BOE**	**Amount**	**per BOE**	**Amount**	**per BOE**
Production costs, excluding ad valorem and production taxes	$ 14,027,461	$ 18.98	$ 11,497,759	$ 15.43	$ 10,390,041	$ 13.52
Total production costs, including ad valorem and production taxes	$ 14,266,784	$ 19.31	$ 11,685,817	$ 15.68	$ 10,604,594	$ 13.80

* BOE computed on units of production using a six to one conversion ratio of MCF's to barrels.

Drilling Activity

Our productive drilling activity during the past three fiscal years ended June 30, 2019, was limited to five gross (1.2 net) producer wells drilled and completed in fiscal 2019 and another five (1.2 net) producer wells completed in fiscal 2018. We completed one (0.239 net) CO_2 injection well during fiscal 2019 and completed one (0.239 net) CO_2 injection well during fiscal 2018. There were no completions of productive wells in fiscal 2017. No dry wells were drilled in the past three fiscal years.

In connection with establishing a six-well water curtain in advance of Phase V site development, during fiscal 2019 we drilled two (0.48 net) wells and completed three (0.72 net) wells. In fiscal 2018, we had drilled three (0.72 net) wells and in fiscal 2017 one (0.239 net) well was drilled. The three completed wells comprise the northern pad of the water curtain program and commenced injection during fiscal 2019. A pad consists of one gross water source well and two gross water injector wells.

Present Activities

As of June 30, 2019, we have three gross (0.72 net) water curtain wells remaining to be completed. We expect their completions will conclude and the wells to be online by early in our second quarter of fiscal 2020. These wells comprise the southern pad of the curtain program.

For further discussion, see "Highlights for our fiscal year 2019" 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, 2019, 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, 2019.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	—	—	119	28.4	119	28.4
Natural gas	—	—	—	—	—	—
Total	—	—	119	28.4	119	28.4

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2019. 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.

Field	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

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* This table excludes acreage attributable to small overriding royalty interests retained in various formations in the Giddings Field area. Except for de minimis production that began on two leases during fiscal 2019, 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 and no reserves have been assigned to any of the Giddings interests.

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 include 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.

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.

Markets and Customers

Our production is marketed 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 average price differential over WTI, as quoted daily on the New York Mercantile Exchange ("NYMEX"), was approximately $6.89 per barrel during our fiscal year ended June 30, 2019. The differential has increased from the prior year and we expect that a positive LLS price differential will continue, at least in the near future. Our overall average net realized oil price, including the LLS premium and after all adjustments for transportation, marketing and other price differentials, was $4.11 per barrel more than the average WTI NYMEX price for fiscal 2019.

Upon completion of the NGL plant in December 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	**2019**	**2018**
Plains Marketing L.P. (Oil sales from Delhi)	94%	92%
American Midstream Gas Solutions. L.P. (NGL sales from Delhi)	6%	8%
All others	—%	—%
Total	100%	100%

The loss of a 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. More recently, the price of oil per barrel dropped dramatically, starting in the fourth quarter of 2014 and continuing into 2017 before recovering somewhat in late calendar 2018 and then weakening again in 2019. Worldwide factors such as geopolitical, international trade disruptions and tariffs, 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.

Government Regulation

Numerous federal and state laws and regulations govern the oil and gas industry, including environmental laws and regulations. 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 oil and gas 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.

Employment

At June 30, 2019, we had four 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. As a result of the retirement of Randy Keys, President and Chief Executive Officer on May 31, 2018, the Board of Directors named Robert Herlin to act as Interim Chief Executive Officer and to commence a search for a permanent Chief Executive Officer. A special Transition Services Committee of the board was created with one member, William Dozier, to provide additional operational oversight to the Company during the transition to a new Chief Executive Officer. On July 10, 2019, Mr. Jason Brown was appointed by the Board of Directors to serve as President and Chief Executive Officer of the Company. Robert Herlin, remained as Chairman of the Board.

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 Securities and Exchange Commission ("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 $74 per barrel to a low of $27 per barrel over the past four fiscal years ending June 30, 2019. 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 85% of our proved reserves at June 30, 2019 are crude oil reserves and 15% 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 NGL 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 virtually represents 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"), an independent oil and gas company specializing in tertiary recovery with CO_2. 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 (so that such cash flows would not be available for capital expenditures or other purposes). 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. Our Delhi asset is productive from a relatively shallow reservoir but we may pursue assets that produce from deeper reservoirs. Shallower reservoirs usually have lower pressure, which generally translates into lower reserve volumes in place. Deeper reservoirs have higher pressures and usually more reserve volumes, but capturing those reserves often comes at increased drilling and completion risk. 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 extracting natural gas liquids 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 may 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, 2019, one purchaser accounted for 94% of our oil and natural gas liquid 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 liquids 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 plan 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 projects;
- our ability to develop new and 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, (ii) secure all of the development capital necessary to fund its and our cost interests, and further develop the Delhi field, such as advancement of Phase V development in the undeveloped eastern part of the field, (iii) successfully manage technical, operating, environmental, strategic and logistical development and operating risks, and (iv) 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 may 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 volumes, 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 oil and gas operations and 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. These laws and regulations may affect the costs, manner and feasibility of our operations and require us to make significant expenditures in order to comply. 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, failure to comply with these laws and regulations may result in 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 business could be negatively affected by security threats. A cyber attack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, manage operations, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Our technologies, systems, networks, seismic data, reserves information or other proprietary information, and those of our operator, vendors, suppliers, customers and other business partners, may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could otherwise lead to the disruption of our business operations or other operational disruptions in our exploration or production operations. Cyber attacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period and could lead to disruptions in critical systems or the unauthorized release of confidential or otherwise protected information. These events could lead to financial losses from remedial actions, loss of business, disruption of operations, damage to our reputation or potential liability. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. Cyber incidents have increased, and the U.S. government has issued warnings indicating that energy assets may be specific targets of cybersecurity threats. Our systems and insurance coverage for protecting against cybersecurity risks may not be sufficient. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber attacks.

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 Herlin, our Chairman of the Board, Jason Brown, our President and Chief Executive Officer, and David Joe, Senior Vice President, Chief Financial Officer, Treasurer and Corporate Secretary, 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 larger 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, regional or worldwide increases in tariffs or other trade restrictions, 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, production costs could increase, any of 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, 2019, our stock price as traded on the NYSE American ranged from \$5.99 to \$12.32. 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, 2019 our executive officers and directors, in the aggregate, beneficially owned approximately 2.5 million shares, or approximately 7.4% of our beneficial common stock base. Blackrock Fund Advisors, et al controlled approximately 3.5 million shares or approximately 10.6 % of our outstanding common stock, Renaissance Technologies, LLC controlled approximately 2.2 million shares or approximately 6.7% of our outstanding common stock, and JVL Advisors, LLC controlled approximately 2.1 million shares or approximately 6.5%. 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 volumes increased in fiscal 2019 compared to fiscal 2018. Trading volume in our common stock is relatively low compared to larger companies. During the fiscal year ended June 30, 2019, the daily trading volume in our common stock ranged from a low of 45,600 shares to a high of 1,079,500 shares, with average daily trading volume of 180,353 shares compared to average daily volume of 112,015 in fiscal 2018. 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 analysts do not publish research reports about our business, or if they downgrade our stock, the price of our common stock could decline.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. To our knowledge there are three 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 an effective 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

Information regarding our properties is included in “Item 1. Business” above and in “Note 6. Property and Equipment” of the Notes to our Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data,”which information is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 16 – 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, 2019 and 2018, the high and low sales prices for EPM as reported by the NYSE American.

NYSE American: EPM

2019:	High	Low
Fourth quarter ended June 30, 2019	$ 7.40	$ 5.99
Third quarter ended March 31, 2019	$ 8.11	$ 6.44
Second quarter ended December 31, 2018	$ 12.83	$ 6.17
First quarter ended September 30, 2018	$ 12.00	$ 9.60

2018:	High	Low
Fourth quarter ended June 30, 2018	$ 10.50	$ 7.75
Third quarter ended March 31, 2018	$ 8.30	$ 6.70
Second quarter ended December 31, 2017	$ 7.63	$ 6.35
First quarter ended September 30, 2017	$ 8.70	$ 6.35

Shares Outstanding and Holders

As of June 30, 2019, there were 33,183,730 shares of common stock issued and outstanding, held by approximately 250 holders of record. We estimate there are approximately 2,000 individuals and institutions that hold our stock through nominees.

Dividends

We began paying cash quarterly dividends on our common stock in December 2013. Over the last two fiscal years, the Company made the following cash dividends per share:

	Years Ended June 30,	
	2019	2018
Fourth quarter ended June 30,	$0.100	$0.100
Third quarter ended March 31,	$0.100	$0.100
Second quarter ended December 31,	$0.100	$0.075
First quarter ended September 30,	$0.100	$0.075

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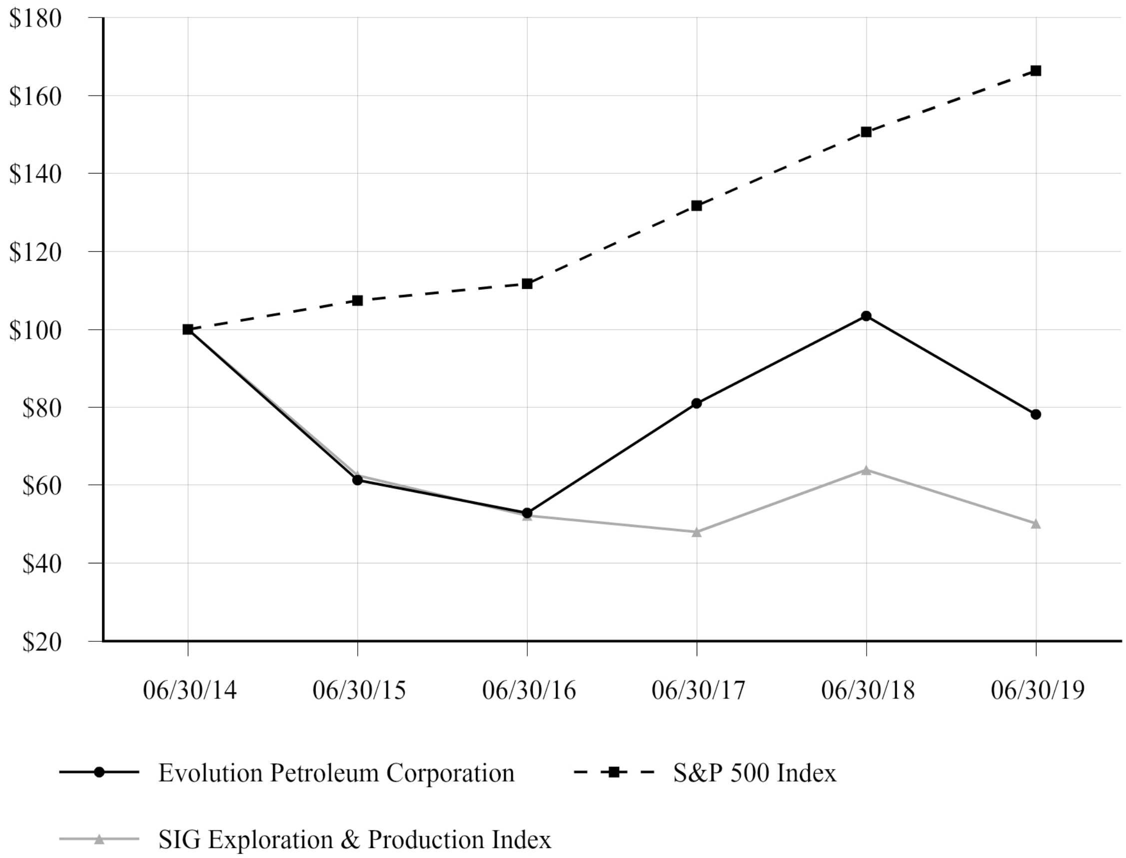
As of June 30, 2019, we had paid twenty-three consecutive quarterly dividends on our common stock. In August 2019, the Company declared a $0.10 per share dividend payable on September 30, 2019. Any future determination with regard to the payment of dividends will be at the discretion of the Board of 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, 2014 to June 30, 2019 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, 2014 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	10,156	(1)	—	
Total	10,156		$ —	852,111
Equity compensation plans not approved by security holders	—		—	—
Total	10,156		$ —	852,111

(1) As of June 30, 2019, 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, 2019, 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 42,833

were unvested as of June 30, 2019), contingent restricted stock grants of 145,646 shares had been reserved (of which 10,156 were unvested as of June 30, 2019) 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 2019, 110,982 awards were made under the 2016 Plan and 852,111 shares of common stock remain available for future grants at June 30, 2019.

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares (or Units) Purchased (1) (2)	(b) Average Price Paid per Share (or Units)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
April 1, 2019 to April 30, 2019	None	Not applicable	Not applicable	$3.4 million
May 1, 2019 to May 31, 2019	None	Not applicable	Not applicable	$3.4 million
June 1, 2019 to June 30, 2019	2,935	$6.19	266,192	$3.4 million

(1) During the fourth quarter ended June 30, 2019, the Company received shares of common stock from certain of its employees which were surrendered in exchange for their payroll tax liabilities arising from vestings of restricted stock and contingent restricted stock. The acquisition cost per share reflects the weighted-average market price of the Company's shares on the dates vested.

(2) On May 12, 2015, the Board of Directors approved a share repurchase program covering up to $5 million of the Company's common stock. Under the program's terms, shares may be repurchased only on the open market and in accordance with the requirements of the Securities and Exchange Commission. The timing and amount of repurchases will depend upon several factors, including financial resources and market and business conditions. There is no fixed termination date for this repurchase program, and the repurchase program may be suspended or discontinued at any time. Such shares are initially recorded as treasury stock, then subsequently canceled. The Company repurchased 430 shares in June 2019 at an average price of $6.07 per share. There were no other program purchases in fiscal 2019.

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,				
	2019	2018	2017	2016	2015
Income Statement Data					
Revenues	$ 43,229,621	$ 40,773,527	$ 34,253,681	$ 26,349,502	$ 27,841,265
Cost of revenues	14,266,784	11,685,817	10,604,594	9,133,111	9,355,613
Depreciation, depletion, and amortization	6,253,083	6,102,288	5,779,069	5,214,174	3,650,603
General and administrative expense	5,072,931	6,773,781	4,985,408	9,079,597	6,256,783
Restructuring charges	—	—	4,488	1,257,433	(5,431)
Income from operations	17,636,823	16,211,641	12,880,122	1,665,187	8,583,697
Other income (expense)	1,222,604	(25,126)	4,855	32,565,954	(147,619)
Income tax provision (benefit)	3,482,361	(3,431,969)	4,840,664	9,570,779	3,444,221
Net income attributable to the Company	$ 15,377,066	$ 19,618,484	$ 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	$ 15,377,066	$ 19,618,484	$ 6,790,883	$ 23,986,060	$ 4,317,555
Earnings per common share:					
Basic	$ 0.46	$ 0.59	$ 0.21	$ 0.73	$ 0.13
Diluted	$ 0.46	$ 0.59	$ 0.21	$ 0.73	$ 0.13

	June 30, 2019	June 30, 2018	June 30, 2017	June 30, 2016	June 30, 2015
Balance Sheet Data					
Total current assets	$ 35,178,927	$ 32,147,556	$ 26,142,527	$ 37,086,450	$ 23,693,048
Total assets	95,761,844	93,662,544	88,268,668	97,451,051	69,882,727
Total current liabilities	2,752,694	4,430,214	2,718,894	8,528,908	9,329,257
Total liabilities	15,635,986	16,373,065	19,798,813	21,129,901	21,306,150
Stockholders' equity	80,125,858	77,289,479	68,469,855	76,321,150	48,576,577
Number of common shares outstanding	33,183,730	33,080,543	33,087,308	32,907,863	32,845,205
Working capital, net	32,426,233	27,717,342	23,423,633	28,557,542	14,363,791
Cash dividends to common stockholders	13,272,058	11,594,541	8,432,435	6,565,823	9,833,642

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

Executive Overview

Results of Operations

Liquidity and Capital Resources

Critical Accounting Policies

Executive Overview

General

Evolution Petroleum Corporation is an oil and gas company focused on delivering a sustainable dividend yield to its stockholders through the ownership, management and development of oil and gas properties. The Company's long-term goal is to build a diversified portfolio of oil and gas assets primarily through acquisitions, while seeking opportunities to maintain and increase production through selective development, production enhancement and other exploitation efforts on its properties.

Our producing assets consist of our interests in the Delhi Holt-Bryant Unit in the Delhi field in Northeast Louisiana, a CO_2 enhanced oil recovery project, and a de minimis overriding royalty interest retained in a past divestiture.

By policy, every employee and director maintains a beneficial ownership position in our common stock. We believe this ownership helps ensure that the interests of our employees and directors are aligned with our stockholders.

In May 2018, our then President and Chief Executive Officer elected to retire as of May 31, 2018. Robert Herlin, our Chairman of the Board, founder and previous CEO, was appointed by the board to the position of Interim CEO. A special Transition Services Committee of the board was created with one member, William Dozier, to provide additional operational oversight to the Company during the transition to a new CEO. On July 10, 2019, Mr. Jason Brown, age 42, was appointed by the Board of Directors to serve as President and Chief Executive Officer of the Company. Robert Herlin, remained as Chairman of the Board.

Highlights for our 2019 Fiscal Year

- We recognized net income of $15.4 million, or $0.46 per diluted common share, our eighth consecutive year of reporting net income
- We funded all operations, including $5.2 million of capital spending, from internal resources and remained debt free
- We returned $13.3 million to common shareholders in the form of cash dividends
- Oil and NGL revenues increased by $2.5 million to $43.2 million, an increase of 6%
- We increased working capital by 17% to $32.4 million at June 30, 2019, with cash on hand of $31.6 million. The twelve well infill program, consisting of ten producer wells and two CO_2 injector wells, was completed and on production during fiscal 2019, converting 536 MBOE of proved undeveloped to proved developed reserves
- Capital expenditures for the six-well water curtain program and related infrastructure preceding the planned Delhi Phase V development is almost complete. The first pad commenced operations during fiscal 2019 and the second pad is expected to begin injections during our second quarter of fiscal 2020

Oil & Natural Gas Liquids Reserves (based on SEC average NYMEX WTI oil price of $61.62 per barrel at June 30, 2019)

- **Delhi proved oil equivalent reserves at June 30, 2019 were 9.0 MMBOE**, a 4% decrease from the previous year. The Standardized Measure for proved reserves increased 7% to $127 million, reflecting a rise in realized commodity prices from $54.71 to $58.50 per BOE. Our proved reserves are 85% crude oil and 15% natural gas liquids, and of these proved reserves, 82% are classified as proved developed and producing and 18% are proved undeveloped.
- **Delhi probable reserves at June 30, 2019 were 4.8 MMBOE**, a 7% increase over the previous year. 87% of these reserves are classified as probable developed and producing, as they are incremental reserves associated with existing developed and producing locations. No additional capital investment is required beyond what is captured in proved reserves.

- **Delhi possible reserves at June 30, 2019 were 4.3 MMBOE**, a 7% decrease over the previous year. 91% of these reserves are classified as possible developed and producing, as they are incremental reserves associated with existing developed and producing locations. No additional capital investment is required beyond what is captured in proved reserves.

The following table is a summary of our proved, probable and possible reserves as of June 30, 2019 and 2018:

	Proved			Probable			Possible		
	2019	2018	Change	2019	2018	Change	2019	2018	Change
Reserves MMBOE	9.0	9.4	(4)%	4.8	4.5	7%	4.3	4.6	(7)%
% Developed	82%	78%	5 %	87%	80%	9%	91%	88%	3 %
Liquids %	100%	100%	— %	100%	100%	—%	100%	100%	— %
Standardized Measure ($MM)	$ 127	$ 119	7 %						
PV-10* ($MM)	$ 157	$ 146	8 %						

* 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 1. "Business - Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues."* 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 oil and gas companies, and that it is relevant and useful in 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 is reconciled to the Standardized Measure in *Item 1. Business*. Probable and possible reserves are not recognized as GAAP, nor is there a comparable GAAP measure.

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

Delhi Field

Our interests in the Delhi field consist of a 23.9% working interest (with associated 19.0% net revenue interest) and separate overriding royalty and mineral interests of 7.2%. This yields a total net revenue interest of 26.2%. The Delhi field is operated by Denbury Onshore, LLC (the "operator"), a subsidiary 100% owned by Denbury Resources Inc. .

Proved reserves volumes totaled 9.0 MMBOE with a Standardized Measure of $127 million and a PV-10* value of $157 million compared to the prior year's 9.4 MMBOE with a Standardized Measure of $119 million and a PV-10* value of $146 million. Improved performance of producing wells has led to a 0.152 MMBOE, or 2%, positive revision in proved oil reserves. Performance from the NGL plant was improved via capitalized modifications resulting in a 0.199 MMBOE, or 16%, positive revision to NGL reserves. Probable reserve volumes at Delhi were 4.8 MMBOE, an increase of 7% compared to 4.5 MMBOE in the prior year. Possible reserves volumes at Delhi were 4.3 MMBOE, a decrease of 7% compared to 4.6 MMBOE in the prior year. The reclassification to probable from possible are primarily the result of timing and recent performance.

Gross production at Delhi in the fourth quarter of fiscal 2019 was 7,843 BOEPD, a 2% increase compared to 7,687 BOEPD in the third fiscal quarter. Oil production was 6,364 BOPD, a 2% decrease from the third fiscal quarter's 6,474 BOPD. NGL production in the fourth quarter was 1,479 BOEPD, 22% higher than prior quarter production of 1,213 BOEPD. Oil production was impacted by compressor downtime during the fourth quarter. Earlier in the year, the operator modified the flow regime of the recycle facility which led to improved NGL production over the past two quarters. However, this modification resulted in compressor issues causing the downtime in the fourth quarter. The compressor was repaired and oil production recovered in July. We expect NGL production to be approximately 1,100 to 1,200 BOEPD over the next several months. The operator is investigating solutions to recapture the NGL rates seen in the fourth quarter. All twelve wells in the infill program initiated in fiscal 2018 have been completed, and consist of two CO_2 injection wells and ten producer wells.

The average oil price realized by Evolution during the fourth quarter of fiscal 2019 was $64.77 compared to $59.12 during the previous quarter. The average NGL price realized by Evolution during the fourth quarter of fiscal 2019 was $15.27 per barrel compared to $16.37 during the previous quarter. Evolution continues to benefit from the premium that Delhi field oil receives selling under Louisiana Light Sweet ("LLS") pricing, as compared to the more widely known West Texas Intermediate ("WTI") price, and the oil is shipped to market directly by pipeline, the most efficient means of transportation from the field. Our received NGL price for royalty production is burdened by a capital recovery charge, which is mostly offset by our working interest share of such capital recovery that is reflected as a reduction in lease operating expense.

Our overall lifting costs for the year were $19.31 per BOE increased 23% from $15.68 per BOE in the prior year. Gross CO_2 purchase volume rates for the fiscal 2019 averaged 85.2 MMcf per day, compared to 65.0 MMcf per day in the prior year, a 31% increase. This increase together with an 8% higher price per mcf resulted in a 41% increase in CO_2 cost compared to the prior year. Our cost of purchased CO_2, the largest single component of operating costs, is directly tied to the price of oil sold from the Delhi field. Other lease operating expenses for the fiscal 2019 increased 9.1% compared to the prior year, primarily due to higher fuel gas expense, labor and chemicals.

For fiscal 2019, our gross NGL production was 1,171 BOEPD, which sold at an average price of $21.87 per barrel, compared to prior year gross production of 976 BOEPD for which we realized $28.06 per barrel. Production from the NGL plant is transported by truck to a processing plant in East Texas, and therefore bears a material transportation charge. Plant efficiencies have improved from the prior year and the higher realized price reflects both the impact of higher oil prices and improvements in meeting the purchaser's specification requirements. Under the operator's marketing contract, we receive market index pricing for each NGL component, based on the processed yield, less transportation, processing fees and other deductions. Our current mix of products is very rich containing higher value NGL's, such as pentanes and butane. Market pricing for our NGL's during the fourth quarter averaged approximately 36% of WTI prices (net realized price is after deduction of transportation and fractionation charges). NGL prices have fallen significantly from a peak in late 2018 in response to worldwide supply and demand. Historically, NGL demand has had a seasonal pattern with prices tending to be higher in the cooler months of the year. Accordingly, the relationship between NGL prices and WTI has fluctuated over time and we expect such volatility to continue.

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 supplies excess power to the CO_2 recycle facility. 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 approximately $6.00 per BOE for 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. Development of unquantified volumes is dependent upon the timing of excess capacity within the processing plant and oil price. We continue to believe that this high quality and economically viable project will be executed as planned, subject to oil price volatility.

Results of Operations
Years Ended June 30, 2019 and 2018

Revenues

Compared to the the prior fiscal year, fiscal 2019 revenues increased 6.0% due to 6.9% higher realized commodity prices partially offset by a very slight decrease in production volumes. The following table summarizes total production volumes, daily production volumes, average realized prices and revenues:

	Years Ended June 30,			
	2019	2018	Variance	Variance %
Oil and gas production				
Crude oil revenues	$ 40,779,052	$ 38,153,417	$ 2,625,635	6.9 %
NGL revenues	2,449,359	2,620,110	(170,751)	(6.5)%
Natural gas revenues	1,210	—	1,210	n.m.
Total revenues	$ 43,229,621	$ 40,773,527	$ 2,456,094	6.0 %
Crude oil volumes (Bbl)	626,879	651,931	(25,052)	(3.8)%
NGL volumes (Bbl)	112,013	93,366	18,647	20.0 %
Natural gas volumes (Mcf)	459	—	459	n.m.
Equivalent volumes (BOE)	738,968	745,297	(6,329)	(0.8)%
Crude oil (BOPD, net)	1,717	1,786	(69)	(3.9)%
NGLs (BOEPD, net)	307	256	51	19.9 %
Natural gas (BOEPD, net)	1	—	1	n.m
Equivalent volumes (BOEPD, net)	2,025	2,042	(17)	(0.8)%
Crude oil price per Bbl	$ 65.05	$ 58.52	$ 6.53	11.2 %
NGL price per Bbl	21.87	28.06	(6.19)	(22.1)%
Natural gas price per Mcf	2.64	—	2.64	— %
Equivalent price per BOE	$ 58.50	$ 54.71	$ 3.79	6.9 %

n. m. Not meaningful.

Production Costs

The $2.6 million increase in production costs was due to a 41% increase in CO_2 costs together with 9% higher other production costs.

	Years Ended June 30,			
	2019	2018	Variance	Variance %
CO_2 costs (a)	$ 6,674,905	$ 4,729,506	$ 1,945,399	41.1%
Other production costs	7,591,879	6,956,311	635,568	9.1%
Total production costs	$ 14,266,784	$ 11,685,817	$ 2,580,967	22.1%
CO_2 costs per BOE	$ 9.03	$ 6.35	$ 2.68	42.2%
All other production costs per BOE	10.28	9.33	0.95	10.2%
Production costs per BOE	$ 19.31	$ 15.68	$ 3.63	23.2%

(a) Under our contract with the operator, purchased CO_2 is priced at 1% of the realized oil price in the field per Mcf, plus sales taxes of approximately 8.5% and transportation costs of $0.20 per mcf. Transportation costs will decline effective January 1, 2020 as per contract terms.

	Years Ended June 30,			
	2019	2018	Variance	Variance %
CO_2 costs per mcf	$ 0.90	$ 0.83	$ 0.07	8.4%
CO_2 volumes (MMcf per day, gross)	85.2	65.0	20.2	31.1%

The $1.9 million increase in CO_2 costs was due to a 31% increase in purchased volumes together with a 8.4% increase in price per mcf reflecting the higher realized oil price. The increase in other production costs primarily consisted of higher costs of $0.3 million for fuel gas expense, $0.2 million for labor, and $0.1 million for chemicals.

Depletion, Depreciation and Amortization ("DD&A")

DD&A expense was 2.5% higher compared to the same year-ago period principally due to a 3.4% higher oil and gas DD&A rate as production volumes were virtually unchanged from fiscal 2018.

	Years Ended June 30,			
	2019	2018	Variance	Variance %
DD&A of proved oil and gas properties	$ 6,122,515	$ 5,980,307	$ 142,208	2.4 %
Depreciation of other property and equipment	15,498	18,127	(2,629)	(14.5)%
Amortization of intangibles	13,564	13,564	—	— %
Accretion of asset retirement obligations	101,506	90,290	11,216	12.4 %
Total DD&A	$ 6,253,083	$ 6,102,288	$ 150,795	2.5 %
Oil and gas DD&A rate per BOE	$ 8.29	$ 8.02	$ 0.27	3.4 %

General and Administrative Expenses

Expenses for the fiscal 2019 decreased $1.7 million, or 25.1%, to $5.1 million from the same year-ago period primarily due to higher fiscal 2018 expenses such as $0.8 million of higher consulting and legal costs for acquisition pursuits, $0.6 million of litigation expense, $0.5 million of non-cash stock compensation expense and $0.3 million of compensation costs associated with the retirement of the then Chief Executive Officer, partially offset by $0.3 million of increased Board expense for fiscal 2019 during the search for a new Chief Executive Officer and $0.2 million of related executive search fees.

Other Income and Expenses

Other income and expense (net) increased due primarily to the $1.1 million breakup fee related to our Enduro stalking horse bid received during August 2018, plus higher earned interest income due to increasing interest rates in fiscal 2019.

	Years Ended June 30,			
	2019	2018	Variance	Variance %
Enduro transaction breakup fee	1,100,000	—	1,100,000	n.m.
Interest and other income	239,150	85,654	153,496	179.2%
Interest expense	(116,546)	(110,780)	(5,766)	5.2%
Total other income, net	$ 1,222,604	$ (25,126)	$ 1,247,730	n.m.

n. m. Not meaningful.

Net Income

Net income available to common stockholders for the year ended June 30, 2019 decreased $4.2 million, or 22%, to $15.4 million compared to the prior year primarily due to a non-recurring prior year deferred tax credit of $6.0 million, partially offset by a $2.7 million, or 17% increase, in income before income taxes. This fiscal 2018 deferred tax benefit resulted from the revaluation of our deferred income tax liabilities at December 31, 2017 to reflect the lower federal statutory rate under the Tax Cut and Jobs Act.

	Years Ended June 30,			
	2019	2018	Variance	Variance %
Income before income taxes	18,859,427	16,186,515	2,672,912	16.5 %
Income tax provision (benefit)	3,482,361	(3,431,969)	6,914,330	(201.5)%
Net income available to common stockholders	$ 15,377,066	$19,618,484	$ (4,241,418)	(22.0)%
Income tax provision as a percentage of income before income taxes	19%	(37)%		

Excluding the effect of the $6.1 million tax benefit from income taxes for the nine months ended March 31, 2018, income tax as a percentage of income before income taxes would have been approximately 18%. For the years ended June 30, 2019 and 2018, our respective statutory federal tax rates were 21% and 27.55%, as we used a blended rate during our fiscal 2018 in which the Tax Cut and Jobs Act was enacted. The benefit of the lower statutory rate in the current year was partially offset by a decreased benefit from depletion in excess of basis as much of our depletion carryover had been utilized by June 30, 2018.

Liquidity and Capital Resources

At June 30, 2019, we had $31.6 million in cash and cash equivalents (and no restricted cash) and $27.7 million of cash, cash equivalents and restricted cash at June 30, 2018.

In addition, we have a senior secured reserve-based credit facility (the "Facility") with a maximum capacity of $50 million. The Facility had $40 million of undrawn elected borrowing base availability on June 30, 2019. Under the Facility the borrowing base shall be determined semiannually as of May 15 and November 15. There have been no borrowings under the Facility, which matures on April 11, 2021, and it is secured by substantially all of the Company's assets.

During the current fiscal year, we amended the credit agreement to broaden the definition for Use of Proceeds to provide funds, limited to an amount not in excess of 25% of the borrowing base, for investments into cash flow generating assets complimentary to the production of oil and gas.

Any future borrowings bear interest, at the Company's option, at either LIBOR plus 2.75% or the Prime Rate, as defined under the Facility, plus 1.0%. The Facility contains covenants that 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 $50.0 million, each as defined in the Facility. The Facility also contains other customary affirmative and negative covenants and events of default. As of June 30, 2019, the Company was in compliance with all covenants contained in the Facility.

During the year ended June 30, 2019, we funded our operations, capital expenditures and cash dividends with cash generated from operations resulting in an increase of $3.9 million in cash. As of June 30, 2019, our working capital was $32.4 million, an increase of $4.7 million over working capital of $27.7 million at June 30, 2018.

We have historically funded our operations through cash from operations and working capital. Our primary source of cash is the sale of oil and natural gas liquids production. A portion of these cash flows are 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. The Company expects to manage future development activities in the Delhi field within the boundaries of its operating cash flow and existing working capital.

We may choose to pursue new growth opportunities through acquisitions or other transactions. In addition to our cash on hand, we have access to at least $40 million of undrawn elected borrowing base availability under our senior secured credit facility. In addition we have an effective shelf registration statement with Securities and Exchange Commission under which we may issue up to $500 million of new debt or equity securities. If we choose to pursue new growth opportunities, 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 issue additional equity at this time.

Our other significant use of cash is our on-going cash dividend program. The Board of Directors instituted a cash dividend on our common stock in December 2013 and we have since paid twenty-three consecutive quarterly dividends. Distribution of a large portion 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 cash dividends over time as appropriate. On August 9, 2019, the Board declared the next quarterly common stock dividend of $0.10 per share, which will be paid on September 30, 2019 to stockholders of record on September 13, 2019. The Board reviews the quarterly dividend rate in view of our financial position and operations, forecasted results, including the outlook for oil and NGL prices, the timing of further expansion of Delhi field development and other potential growth opportunities.

Capital Budget - Delhi Field

During the year ended June 30, 2019, we incurred $5.2 million of capital expenditures at Delhi. This spending included $0.7 million for capital upgrades to the NGL plant, injection lines and facilities, $1.1 million for CO_2 conformance projects and capital maintenance, $1.6 million for Phase V infrastructure (i.e. water curtain wells) in the eastern portion of the field, and $1.8 million for the infill drilling program.

The twelve well infill drilling program in the Delhi field is complete and the wells are contributing. There are ten producing oil wells and two CO_2 injection wells. While we intended to drill four injection wells, two of the planned injectors were completed as producers. These wells may be re-completed as injectors at a later date. The injectors and producers were drilled and completed in areas needing additional support to sweep oil. Since the program's inception in fiscal 2018, our net capital expenditures have totaled $4.6 million.

We expect to continue to perform conformance workover projects and will likely incur additional maintenance capital expenditures. Such amounts are not known or approved yet but we expect them to run in the $1.0 to $2.0 million magnitude as it has the past two fiscal years.

Our proved undeveloped reserves at June 30, 2019 included 1,583 MBOE of reserves and approximately $8.6 million of future development costs associated with Phase V development in the eastern portion of the field. Such development requires participation by both the operator and Evolution, and the operator has not yet finalized its capital expenditure budget for 2020. Based our discussions with the operator, in fiscal 2020, we expect to spend about $0.6 million to complete the south water curtain in preparation for the Phase V development, which is expected to commence late in fiscal 2020. In our last three fiscal years we have incurred a total of $3.1 million on the water curtain program in advance of this development. The timing of Phase V is also dependent, in part, on the field operator's available funds and capital spending plans and priorities within its portfolio of properties.

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

Overview of Cash Flow Activities

The table below compares a summary of our condensed consolidated statements of cash flows for year ended June 30, 2019 and 2018.

	June 30,		
Increases (Decreases) in Cash:	**2019**	**2018**	**Difference**
		(In Millions)	
Net cash provided by operating activities	$ 24.1	$ 20.5	$ 3.6
Net cash used in investing activities	(6.8)	(3.7)	(3.1)
Net cash used in financing activities	(13.4)	(12.2)	(1.2)
Change in cash, cash equivalents and restricted cash	$ 3.9	$ 4.6	$ (0.7)

Cash provided by operating activities in the current year increased $3.6 million compared to the fiscal 2018 due to a $5.8 million increase in cash provided by non-cash expenses and $2.1 million increase in cash provided from current operating assets and liabilities partially offset by a $4.3 million decrease in cash provided by net income. Fiscal 2018 total non-cash expenses were impacted by the one-time $6.0 million deferred income tax credit related to enactment of the Tax Cut and Jobs Act.

Cash used in investing activities increased $3.1 million due to higher capital expenditure disbursements in the 2019 period.

Cash used in financing activities increased $1.2 million due to $1.6 million of higher cash dividends, reflecting a higher quarterly dividend rate of $0.10 per share throughout fiscal 2019 compared to $0.075 per share during the first half of fiscal 2018 and $0.10 per share paid the subsequent two quarters, partially offset by $0.4 million of lower common share repurchases related to stock-based awards vestings.

Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2019, 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	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Contractual Obligations					
Purchase commitments in connection with joint interest agreement	$ 861,674	$ 861,674	$ —	$ —	$ —
Operating lease	182,208	34,322	147,886	—	—
Other Obligations					
Asset retirement obligations	1,610,845	50,244	—	—	1,560,601
Total Obligations	$ 2,654,727	$ 946,240	$ 147,886	$ —	$ 1,560,601

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 – Summary of Significant Accounting Policies* of 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, 2019, 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, 2019 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, 2019 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $313,000, $658,000 and $1,042,000, 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 drilled five years from the initial recognition date of such reserves, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and gas reserves using an average price based on the previous 12-month unweighted arithmetic average first-day-of-the-month price rather than year-end prices, revises the disclosure requirements for oil and gas operations, and revises accounting for the limitation on capitalized costs for full cost companies.

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, 2019, 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. This technique uses a geometric Brownian motion model with defined variables and randomly generates values for each variable through multiple trials. Variables include 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 award on the date of grant. 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 and, for certain awards, the Company's share price attaining a set target.

Recent Accounting Pronouncements. See Note 2 – Summary of Significant Accounting Policies to our Consolidated Financial Statements for discussion of the recent accounting pronouncements issued by the Financial Accounting Standards Board.

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements as of June 30, 2019.

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, 2019.

Item 8. Financial Statements

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and Subsidiaries (the "Company") as of June 30, 2019 and 2018, the related consolidated statements of operations, cash flows and changes in stockholders' equity for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of June 30, 2019 and 2018, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of June 30, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated September 12, 2019 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Moss Adams LLP

Houston, Texas
September 12, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation

Opinion on Internal Control over Financial Reporting

We have audited Evolution Petroleum Corporation and Subsidiaries' (the "Company") internal control over financial reporting as of June 30, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of Evolution Petroleum Corporation and Subsidiaries as of June 30, 2019 and 2018, the related consolidated statements of operations, cash flows and changes in stockholders' equity for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated September 12, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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 included in Item 9A. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control Over Financial Reporting

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

/s/ Moss Adams LLP

Houston, Texas
September 12, 2019

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2019	June 30, 2018
Assets		
Current assets		
Cash and cash equivalents	$ 31,552,533	$ 24,929,844
Restricted cash	—	2,751,289
Receivables	3,168,116	3,941,916
Prepaid expenses and other current assets	458,278	524,507
Total current assets	35,178,927	32,147,556
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties—full-cost method of accounting, of which none were excluded from amortization	60,346,466	61,239,746
Other property and equipment, net	26,418	30,407
Total property and equipment, net	60,372,884	61,270,153
Other assets, net	210,033	244,835
Total assets	$ 95,761,844	$ 93,662,544
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 2,084,140	$ 3,432,568
Accrued liabilities and other	537,755	874,886
State and federal taxes payable	130,799	122,760
Total current liabilities	2,752,694	4,430,214
Long term liabilities		
Deferred income taxes	11,322,691	10,555,435
Asset retirement obligations	1,560,601	1,387,416
Total liabilities	15,635,986	16,373,065
Commitments and contingencies (Note 16)		
Stockholders' equity		
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 33,183,730 and 33,080,543 shares as of June 30, 2019 and 2018, respectively	33,183	33,080
Additional paid-in capital	42,488,913	41,757,645
Retained earnings	37,603,762	35,498,754
Total stockholders' equity	80,125,858	77,289,479
Total liabilities and stockholders' equity	$ 95,761,844	$ 93,662,544

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Years Ended June 30,	
	2019	2018
Revenues		
Crude oil	$ 40,779,052	$ 38,153,417
Natural gas liquids	2,449,359	2,620,110
Natural gas	1,210	—
Total revenues	43,229,621	40,773,527
Operating costs		
Production costs	14,266,784	11,685,817
Depreciation, depletion and amortization	6,253,083	6,102,288
General and administrative expenses*	5,072,931	6,773,781
Total operating costs	25,592,798	24,561,886
Income from operations	17,636,823	16,211,641
Other		
Enduro transaction breakup fee	1,100,000	—
Interest and other income	239,150	85,654
Interest (expense)	(116,546)	(110,780)
Income before income tax provision	18,859,427	16,186,515
Income tax provision (benefit)	3,482,361	(3,431,969)
Net income attributable to common shareholders	$ 15,377,066	$ 19,618,484
Earnings per common share		
Basic	$ 0.46	$ 0.59
Diluted	$ 0.46	$ 0.59
Weighted average number of common shares outstanding		
Basic	33,160,283	33,126,469
Diluted	33,169,718	33,178,535

* General and administrative expenses for the years ended June 30, 2019 and 2018 included non-cash stock-based compensation expense of $888,162 and $1,366,764, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended June 30,	
	2019	**2018**
Cash flows from operating activities		
Net income attributable to the Company	$ 15,377,066	$ 19,618,484
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	6,268,239	6,158,555
Stock-based compensation	888,162	1,366,764
Deferred income taxes	767,256	(5,270,856)
Changes in operating assets and liabilities:		
Receivables	773,800	(1,215,214)
Prepaid expenses and other current assets	66,229	(136,835)
Accounts payable and accrued expenses	(90,891)	(107,081)
Income taxes payable	8,039	122,760
Net cash provided by operating activities	24,057,900	20,536,577
Cash flows from investing activities		
Development of oil and natural gas properties	(6,746,142)	(3,690,845)
Capital expenditures for other property and equipment	(11,509)	(7,846)
Other assets	—	(19,282)
Net cash used by investing activities	(6,757,651)	(3,717,973)
Cash flows from financing activities		
Common share repurchases, including shares surrendered for tax withholding	(156,791)	(571,083)
Common stock dividends paid	(13,272,058)	(11,594,541)
Net cash provided by (used in) financing activities	(13,428,849)	(12,165,624)
Net increase in cash, cash equivalents and restricted cash	3,871,400	4,652,980
Cash, cash equivalents and restricted cash, beginning of year	27,681,133	23,028,153
Cash, cash equivalents and restricted cash, end of year	$ 31,552,533	$ 27,681,133

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the statements of financial position that sum to the totals of the such amounts shown in the statements of cash flows.

	Years Ended June 30,	
	2019	**2018**
Cash and cash equivalents	$ 31,552,533	$ 24,929,844
Restricted cash included in current assets	—	2,751,289
Total cash, cash equivalents and restricted cash shown in the statements of cash flows	$ 31,552,533	$ 27,681,133

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, 2019 and 2018

	Common Stock		Additional			Total
	Shares	Par Value	Paid-in Capital	Retained Earnings	Treasury Stock	Stockholders' Equity
Balance, June 30, 2017	33,087,308	$ 33,087	$40,961,957	$ 27,474,811	$ —	$ 68,469,855
Issuance of restricted common stock	183,537	183	(183)	—	—	—
Forfeitures of restricted stock	(117,094)	(117)	117	—	—	—
Common share repurchases, including shares surrendered for tax withholding	(73,208)	—	—	—	(571,083)	(571,083)
Retirements of treasury stock	—	(73)	(571,010)	—	571,083	—
Stock-based compensation	—	—	1,366,764	—	—	1,366,764
Net income attributable to the Company	—	—	—	19,618,484	—	19,618,484
Common stock cash dividends	—	—	—	(11,594,541)	—	(11,594,541)
Balance, June 30, 2018	33,080,543	33,080	41,757,645	35,498,754	—	77,289,479
Issuance of restricted common stock	121,611	122	(122)	—	—	—
Common share repurchases, including shares surrendered for tax withholding	(18,424)	—	—	—	(156,791)	(156,791)
Retirements of treasury stock	—	(19)	(156,772)	—	156,791	—
Stock-based compensation	—	—	888,162	—	—	888,162
Net income attributable to the Company	—	—	—	15,377,066	—	15,377,066
Common stock cash dividends	—	—	—	(13,272,058)	—	(13,272,058)
Balance, June 30, 2019	33,183,730	$ 33,183	$42,488,913	$ 37,603,762	$ —	$ 80,125,858

See accompanying notes to consolidated financial statements.

Note 1 – Organization and Basis of Preparation

Nature of Operations. Evolution Petroleum Corporation is an oil and gas company focused on delivering a sustainable dividend yield to its shareholders through the ownership, management and development of producing oil and gas properties. The Company's long-term goal is to build a diversified portfolio of oil and gas assets primarily through acquisition, while seeking opportunities to maintain and increase production through selective development, production enhancement and other exploitation efforts on its properties. Our largest active investment is our interest in a CO_2 enhanced oil recovery project in Louisiana's Delhi field.

Principles of Consolidation and Reporting. Our consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements of prior periods 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.

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.

Restricted Cash. Funds legally designated for a specified purpose are classified as restricted cash. Such a balance is classified on the statement of financial position as either current or non-current depending on its expected use.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable consist 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 receivable if it is determined that collection of all or a part of an outstanding balance is not probable. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2019 and 2018, no allowance for doubtful accounts was considered necessary.

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

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

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; and 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, 2019 and 2018.

Other Property and Equipment. Other property and equipment includes building leasehold improvements, data processing and telecommunications equipment, office furniture and office equipment. 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. The assets are depreciated using the straight-line method. 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, restricted cash, 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 and geometric Brownian motion techniques applied to 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. 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. Our revenues are comprised solely of revenues from customers from the sale of crude oil, NGLs and natural gas. The Company believes that the disaggregation of revenue on its consolidated statements of operations into these three major product types appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on our single geographic location. Crude oil, NGL and natural gas revenues are recognized at a point in time when production is sold to a purchaser at an index-based, determinable price, delivery has occurred, control has transferred and collectibility of the revenue is probable. The transaction price used to recognize revenue is a function of the contract billing terms which reference index price sources used by the industry. Revenue is invoiced by calendar month based on volumes at contractually based rates with payment typically required within 30 days for crude oil and 60 days for NGLs after the end of the production month. At the end of each month when the performance obligations have been satisfied, the consideration can be reasonably estimated and amounts due from customers are accrued in “Receivables” in our consolidated balance sheets. As of June 30, 2019 and 2018 receivables from contracts with customers were $3.2 million and $3.9 million, respectively.

Depreciation, Depletion and Amortization ("DD&A"). 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 building improvements, office and computer 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 largest amount of tax benefit that is greater than 50% likely 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.

Recently Adopted Accounting Pronouncements - Revenue Recognition

Effective July 1, 2018, the Company adopted ASU No. 2014-09, Revenue From Contracts With Customers (Topic 606) (“ASC 606”) using the full retrospective method and has applied the standard to all existing contracts. ASC 606 supersedes previous revenue recognition requirements in ASC 605 - Revenue Recognition (“ASC 605”) and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration in exchange for those goods or services. As a result of adopting ASC 606, the Company did not have a cumulative-effect adjustment in retained earnings. The comparative information presented therein for the year ended June 30, 2018 reflects the reclassification on our consolidated statement of operations of $507,685 from “Production Costs” to “Revenue - Natural Gas Liquids” in conformance with ASC 606. These changes to revenue and production costs resulted from the conclusion that the Company did not control the product throughout processing before transferring to the customer. Therefore, costs incurred after the transfer of control are treated as reductions of revenue. Additionally, adoption of ASC 606 did not impact net income attributable to common stockholders, current assets, total assets, current liabilities, total liabilities or stockholders' equity and the Company does not expect that it will do so in future periods.

Other Recently Adopted Accounting Pronouncements

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 investees) 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. Effective July 1, 2018, the Company prospectively adopted ASU 2016-01 without impact to its consolidated financial position or results of operations. Because its investment in Well Lift Inc. does not have a readily determinable fair value, the Company elected to measure this investment at cost less impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of the same issuer, if they were to occur.

Effective July 1, 2018, the Company retrospectively adopted ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments, 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. Adoption had no effect on our current period and comparative consolidated statements of cash flows.

Effective July 1, 2018, the Company prospectively adopted ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Company will apply the clarified definition of business to future acquistions and divestitures.

Recently Issued Accounting Pronouncements

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842) ("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. The Company will adopt ASU 2016-02 effective July 1, 2019, using the modified retrospective approach. The Company will make certain elections allowing it to not reassess contracts that commenced prior to adoption, not to recognize right of use ("ROU") assets or lease liabilities for short-term leases, and will not separate lease components from non-lease components for specified asset classes. As of July 1, 2019, the Company anticipates that the adoption of ASU 2016-02 will result in the recognition of ROU assets and lease liabilities on its consolidated balance sheets of approximately $165,000 related to office space. Accordingly, the Company does not expect ASU 2016-02 to have a significant impact on its consolidated statements of operations or consolidated statements of cash flows. The Company is finalizing its accounting policies, controls, processes, and disclosures that will change as a result of adopting the new standard. As permitted by ASU No. 2018-11, Leases (Topic 842): Targeted Improvements, the Company does not expect to adjust comparative-period financial statements.

In June 2016, the FASB issued ASU 2016-13, Financial Instruments - Credit Losses ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires the use of a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the amendment using a modified retrospective approach to the first reporting period in which the guidance is effective. The adoption of ASU 2016-13 is currently not expected to have a material effect on our consolidated financial statements.

Note 3 – Enduro Purchase and Sale Agreement and "Stalking Horse" Bid

During the first quarter of fiscal 2019, The Company recorded a $1.1 million break-up fee upon the closing of a higher bidder's purchase transaction. During May 2018, the Company had entered into a Purchase and Sale Agreement ("PSA"), to acquire, as the "stalking horse" bidder, certain oil and gas assets from an affiliate of Enduro Resource Partners LLC ("Enduro") for a purchase price of $27.5 million, subject to the outcome of Enduro's Chapter 11 process. Contemporaneous with executing the PSA, the Company made a $2.75 million deposit to an acquisition escrow account which, together with interest earned, comprised the restricted cash balance on the Company's June 30, 2018 consolidated statement of financial position. Earlier in the first quarter of 2019, the Company was repaid its deposit together with related earned interest when a higher bidder first emerged in the bidding process.

The Company's initial and subsequent bids represented offers under Section 363 of the U.S. Bankruptcy Code in Enduro's Chapter 11 proceeding. Such offers are commonly referred to as “stalking horse” bids and are subject to higher bids, in accordance with the bidding procedures approved by the Bankruptcy Court. In connection with the PSA, the Company incurred third party due diligence expenses of $0.4 million, which have been reflected in the Company's consolidated statement of operations for the year ended June 30, 2018.

Note 4 – Receivables

As of June 30, 2019 and June 30, 2018 our receivables consisted of the following:

	June 30, 2019	June 30, 2018
Receivables from oil and gas sales	$ 3,168,116	$ 3,940,998
Other	—	918
Total receivables	$ 3,168,116	$ 3,941,916

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 5 – Prepaid Expenses and Other Current Assets

As of June 30, 2019 and June 30, 2018 our prepaid expenses and other current assets consisted of the following:

	June 30, 2019	June 30, 2018
Prepaid insurance	$ 206,198	$ 198,558
Prepaid federal and state income taxes	121,679	231,920
Retainers and deposits	8,019	11,089
Other prepaid expenses	122,382	82,940
Prepaid expenses and other current assets	$ 458,278	$ 524,507

Note 6 – Property and Equipment

As of June 30, 2019 and June 30, 2018, our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2019	June 30, 2018
Oil and natural gas properties:		
Property costs subject to amortization	$ 95,622,153	$ 90,392,918
Less: Accumulated depreciation, depletion, and amortization	(35,275,687)	(29,153,172)
Unproved properties not subject to amortization	—	—
Oil and natural gas properties, net	60,346,466	61,239,746
Other property and equipment:		
Furniture, fixtures and office equipment, at cost	154,731	143,223
Less: Accumulated depreciation	(128,313)	(112,816)
Other property and equipment, net	$ 26,418	$ 30,407

As of June 30, 2019 and 2018, all oil and gas property costs were being amortized.

During the years ended June 30, 2019 and 2018, the Company incurred capital expenditures of $5.2 million and $5.4 million, respectively, in the Delhi field.

Note 7 – Other Assets

As of June 30, 2019 and June 30, 2018 our other assets consisted of the following:

	June 30, 2019	June 30, 2018
Royalty rights	108,512	108,512
Less: Accumulated amortization of royalty rights	(47,474)	(33,910)
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	(141,927)	(126,771)
Software license	20,662	20,662
Less: Accumulated amortization of software license	(7,462)	(1,380)
Other assets, net	$ 210,033	$ 244,835

Our royalty rights and investment in Well Lift, Inc. ("WLI") resulted from the separation of our artificial lift technology operations in December 2015. We conveyed our patents and other intellectual property to WLI and retained a 5% royalty on future gross revenues associated the technology. We own 17.5% of the common stock of WLI and account for our investment in this private company at cost less impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of the same issuer, if such were to occur. The Company evaluates the investment for impairment when it identifies any events or changes in circumstances that might have a significant adverse effect on the fair value of the investment.

Note 8 – Accrued Liabilities and Other

As of June 30, 2019 and June 30, 2018 our accrued liabilities and other consisted of the following:

	June 30, 2019	June 30, 2018
Accrued incentive and other compensation	$ 369,719	$ 415,182
Accrued severance	—	160,089
Asset retirement obligations due within one year	50,244	35,539
Accrued royalties, including suspended accounts	11,554	11,498
Accrued franchise taxes	5,738	162,805
Accrued ad valorem taxes	100,500	89,773
Accrued liabilities and other	$ 537,755	$ 874,886

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, 2019 and 2018:

	Years Ended	
	2019	2018
Asset retirement obligations — beginning of period	$ 1,422,955	$ 1,288,743
Liabilities incurred	31,268	44,700
Accretion of discount	101,506	90,290
Revisions to previous estimates	55,116	(778)
Asset retirement obligations — end of period	1,610,845	1,422,955
Less: current asset retirement obligations	(50,244)	(35,539)
Long-term portion of asset retirement obligations	$ 1,560,601	$ 1,387,416

Note 10 – Stockholders' Equity

Common Stock

As of June 30, 2019, we had 33,183,730 shares of common stock outstanding.

The Company began paying quarterly cash dividends on common stock in December 2013. As of June 30, 2019, we have cumulatively paid $59.4 million in cash dividends. We paid dividends of $13,272,058 and $11,594,541 from retained earnings to our common shareholders during the years ended June 30, 2019 and 2018, respectively. The following table reflects the dividends paid per common share in each quarter within the respective two fiscal years:

	Fiscal Year	
	2019	**2018**
Fourth quarter ended June 30,	$0.100	$0.100
Third quarter ended March 31,	$0.100	$0.100
Second quarter ended December 31,	$0.100	$0.075
First quarter ended September 30,	$0.100	$0.075

Repurchases of common shares are initially recorded as treasury stock, then subsequently canceled. On May 12, 2015, the Board of Directors approved a share repurchase program covering up to $5 million of the Company's common stock. Since commencement in June 2015, we have repurchased 266,192 shares at an average price of $6.05 per share, for total cost of $1,611,620. The timing and amount of repurchases depends upon several factors, including financial resources, 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 until June 2019 when 430 shares were repurchased at an average price of $6.07 per share. 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.

The Company has also acquired treasury stock from holders of newly vested stock-based awards to fund the recipients' payroll tax withholding obligations. The treasury shares were subsequently canceled. Such shares were valued at fair market value on the date of vesting or date of share repurchase. The following summarizes all treasury stock purchases by fiscal year:

	Fiscal Year	
	2019	**2018**
Number of treasury shares acquired	18,424	73,208
Average cost per share	$ 8.51	$ 7.80
Total cost of treasury shares acquired	$ 156,791	$ 571,083

Tax Treatment of Dividends to Recipients

Based on our current projections for the fiscal year ended June 30, 2019, we expect all common stock dividends for this fiscal year will be treated for tax purposes as qualified dividend income to the recipients. For the fiscal year ended June 30, 2018, all common stock dividends for that fiscal year were treated for tax purposes as qualified dividend income to the recipients.

Note 11—Stock-Based Incentive Plan

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, 2019, 852,111 shares remained available for grant under the 2016 Plan.

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 outstanding grants of restricted common stock awards ("Restricted Stock") and contingent restricted common stock awards ("Contingent Restricted Stock") to employees and directors of the Company.

Restricted Stock and Contingent Restricted Stock

The Company may award grants of both Restricted Stock and Contingent Restricted Stock as part of its long-term incentive plan. Such grants, which expire after a maximum of four years if unvested, contain service-based, performance-based and market-based vesting provisions. The common shares underlying the Restricted Stock grants are issued on the date of grant. Contingent Restricted Stock grants vest only upon the attainment of higher performance-based or market-based vesting thresholds and are issued only upon vesting. Shares underlying Contingent Restricted Stock awards are reserved from the Plan under which they were granted under.

Service-based awards vest with continuous employment by the Company, generally in annual installments over a three or four-year period. Certain awards may contain other vesting periods, including quarterly installments and one-year vesting. Restricted Stock grants which vest based on service are valued at the fair market value on the date of grant and amortized over the service period. During the year ended June 30, 2019, we granted 31,777 service-based Restricted Stock awards and 43,990 market-based awards to employees and 35,215 service-based awards to directors, which have a one-year vesting period. We did not grant any performance-based nor any Contingent Restricted Stock awards, during this fiscal year.

Performance-based grants vest upon the attainment of earnings, revenue and other operational goals and require that the recipient remain an employee or director 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 term of the award. As of June 30, 2019, there were no performance-based awards outstanding.

Market-based awards vest if their respective 2- or 3-year trailing total returns on the Company’s common stock exceed the corresponding total returns of various quartiles of indices consisting of either peer companies or a broad market index of companies in our industry. More recent market-based awards vest if the average of the Company's closing stock prices over defined quarterly measurement periods together with accumulated paid dividends exceeds a defined value. The fair values and expected vesting periods of these awards are 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. Compensation expense for market-based awards is recognized over the expected vesting period using the straight-line method, so long as the holder remains an employee or director 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.

Assumptions used in the Monte Carlo simulation valuations for the year ended June 30, 2019 follow below. There were no market-based awards granted for the year ended June 30, 2018.

	Year Ended June 30, 2019
Weighted average fair value of market-based awards granted	$ 8.24
Risk-free interest rate	2.69%
Expected life in years	2.82
Expected volatility	41.8%
Dividend yield	4.0%

Unvested Restricted Stock awards at June 30, 2019 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Service-based awards	112,381	$ 8.52
Market-based awards	64,302	7.35
Unvested at June 30, 2019	176,683	$ 8.09

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2019:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2019	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2018	199,477	$ 6.83	$ —	
Service-based awards granted	66,992	9.17		
Market-based awards granted	43,990	8.24		
Vested	(133,776)	6.80		
Unvested at June 30, 2019	176,683	$ 8.09	$ 848,262	1.75

The following is a summary of Restricted Stock vestings for the last two fiscal years:

	Year Ended June 30, 2019	Year Ended June 30, 2018
Vesting-date intrinsic value of Restricted Stock	$ 1,141,631	$ 1,622,937
Grant-date fair value of vested Restricted Stock	$ 909,678	$ 1,427,498
Number of awards vesting	133,776	211,960

The following table summarizes Contingent Restricted Stock activity for fiscal 2019:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2019	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2018	28,562	$ 6.06		
Expired	(7,777)	10.05		
Vested	(10,629)	5.67		
Unvested at June 30, 2019	10,156	$ 3.42	$ —	0

All of these outstanding awards at June 30, 2019 are market-based awards.

The following is a summary of Contingent Restricted Stock vestings for the last two fiscal years:

	Year Ended June 30,	
	2019	2018
Vest-date intrinsic value of Contingent Restricted Stock	$ 105,227	$ 347,852
Grant-date fair value of vested Contingent Restricted Stock	$ 60,266	$ 155,744
Number of awards vesting	10,629	46,630

Stock-based Compensation Expense

For the years ended June 30, 2019, and 2018, we recognized stock-based compensation expense related to Restricted Stock and Contingent Restricted Stock grants of $888,162 and $1,366,764.

Note 12 – Supplemental Disclosure of Cash Flow Information

Our supplemental disclosures of cash flow information for the years ended June 30, 2019 and 2018 are as follows:

	June 30,	
	2019	2018
Income taxes paid	$ 2,762,919	$ 1,826,754
Non-cash transactions:		
Increase (decrease) in accrued purchases of property and equipment	(1,603,290)	1,695,218
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	86,384	43,922

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, 2019 and 2018. We believe that we have appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's federal and state income tax returns are open to audit under the statute of limitations for the years ended June 30, 2015 through June 30, 2018 for federal tax purposes and for the years ended June 30, 2016 through June 30, 2018 for state tax purposes. To the extent we utilize net operating losses generated in earlier years, such earlier years may also be subject to audit.

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

	June 30, 2019	June 30, 2018
Current:		
Federal	$ 2,343,512	$ 1,186,649
State	371,593	652,238
Total current income tax provision	2,715,105	1,838,887
Deferred:		
Federal	387,541	(5,498,890)
State	379,715	228,034
Total deferred income tax provision (benefit)	767,256	(5,270,856)
	$ 3,482,361	$ (3,431,969)

For the years ended June 30, 2019 and 2018, respectively, we recognized income tax expense of $3.5 million and an income tax benefit of $(3.4) million reflecting corresponding effective tax rates of 18.5% and (21.2)%. The fiscal 2018 benefit included a one-time $(6.1) million tax benefit, resulting from adjustments of our deferred income tax liabilities in fiscal 2018 due to the enactment of the Tax Cut and Jobs Act (the "Tax Act") during December of 2017. Our effective tax rate will typically differ from the statutory federal rate as a result of state income taxes, primarily in the State of Louisiana, and differences related to percentage depletion in excess of basis, stock-based compensation and other permanent differences. For the years ended June 30, 2019 and 2018, our respective statutory federal tax rates were 21% and 27.55%, as we used a blended rate in the prior fiscal year when the Tax Act was enacted. Depletion in excess of basis had less of an impact on our effective rate in the current year as we utilized all of our depletion carryover in fiscal 2018. The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate to the income tax provision (benefit) in our financial statements.

	June 30, 2019	% of Income Before Income Taxes	June 30, 2018	% of Income Before Income Taxes
Income tax provision (benefit) computed at the statutory federal rate:	$ 3,960,480	21.0 %	$ 4,459,940	27.6 %
Reconciling items:				
Adjustment of deferred income liability for the Tax Act's lower statutory federal tax rate	—	— %	(5,949,389)	(36.8)%
Change in valuation allowance due to enactment of the Tax Act	—	— %	(111,818)	(0.7)%
Expiration of Section 382 tax loss carryforwards	127,410	0.70 %	—	— %
Change in valuation allowance for Section 382 tax loss carryforwards	(127,410)	(0.70)%	—	— %
Depletion in excess of tax basis	(982,302)	(5.1)%	(2,433,530)	(14.9)%
State income taxes, net of federal tax benefit	593,533	3.1 %	718,337	4.4 %
Permanent differences related to stock-based compensation	(73,671)	(0.4)%	(139,333)	(0.9)%
Other	(15,679)	(0.1)%	23,824	0.1 %
Income tax provision (benefit)	$ 3,482,361	18.5 %	$ (3,431,969)	(21.2)%

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.

	Asset (Liability)	
	June 30, 2019	June 30, 2018
Deferred tax assets:		
Non-qualified stock-based compensation	$ 159,090	$ 144,956
Net operating loss carry-forwards	496,082	680,186
Other	20,713	24,207
Gross deferred tax assets	675,885	849,349
Valuation allowance	(53,218)	(180,628)
Total deferred tax assets	622,667	668,721
Deferred tax liability:		
Oil and natural gas properties	(11,945,358)	(11,224,156)
Total deferred tax liability	(11,945,358)	(11,224,156)
Net deferred tax liability	$ (11,322,691)	$ (10,555,435)

As of June 30, 2019, we had a federal tax loss carryforward of approximately $0.6 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 $0.2 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.

Note 14 – Net Income Per Share

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

	June 30,	
	2019	2018
Numerator		
Net income attributable to common shareholders	$ 15,377,066	$ 19,618,484
Denominator		
Weighted average number of common shares – Basic	33,160,283	33,126,469
Effect of dilutive securities:		
Contingent restricted stock grants	9,435	52,066
Weighted average number of common shares and dilutive potential common shares used in diluted EPS	33,169,718	33,178,535
Net income per common share – Basic	$ 0.46	$ 0.59
Net income per common share – Diluted	$ 0.46	$ 0.59

The following were reflected in the calculation of diluted earnings per share in their respective fiscal years:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2019
Contingent Restricted Stock grants	$ —	10,156

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2018
Contingent Restricted Stock grants	$ —	28,562

Note 15 – Credit Agreements

Senior Secured Credit Agreement

On April 11, 2016, the Company entered into a three-year, senior secured reserve-based credit facility ("Facility") in an amount up to $50 million. On May 25, 2018, we entered into the third amendment to our credit agreement governing the revolving credit facility to, among other things, extend the maturity date to April 11, 2021. On December 31, 2018, we entered into the fourth amendment to our credit agreement governing the revolving credit facility to broaden the definition for the Use of Proceeds.

As of June 30, 2019, the Company's elected commitment and borrowing base were $40 million, we were in compliance with all financial covenants and there were no amounts outstanding under the Facility, which is secured by substantially all of the Company's assets.

Under the Facility the borrowing base shall be determined semiannually as of every May 15 and November 15 during the term of the Facility. During the fourth fiscal quarter, the bank performed its periodic spring redetermination of the borrowing base and confirmed our elected amount of $40 million.

Borrowings from the Facility may be used for the acquisition and development of oil and gas properties, investments in cash flow generating assets complimentary to the production of oil and gas, and for letters of credit and other general corporate purposes.

The Facility 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 $50 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. The unamortized balance in debt issuance costs related to the Facility was $27,045 as of June 30, 2019.

Note 16 – Commitments and Contingencies

We are subject to various claims and contingencies in the normal course of business. In addition, from time to time, we receive communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdictions in which we operate. At a minimum, we disclose such matters if we believe it is reasonably possible that a future event or events will confirm a loss through impairment of an asset or the incurrence of a liability. We accrue a loss if we believe it is probable that a future event or events will confirm a loss and we can reasonably estimate such loss and we do not accrue future legal costs related to that loss. Furthermore, we will disclose any matter that is unasserted if we consider it probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable. We expense legal defense costs as they are incurred.

Lease Commitments. We have a non-cancelable office space whose term ends in November 2022. Future minimum lease commitments as of June 30, 2019 under this operating lease is as follows:

For the Years Ended June 30,		
2020	$	34,322
2021		59,945
2022		61,843
2023		26,098
Total	$	182,208

Rent expense for the years ended June 30, 2019 and 2018 was $73,289 and $76,666, respectively.

Note 17 – Concentrations of Credit Risk

Major Customers. 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 or natural gas liquids production from Delhi. Although we have the right to take our working interest production at Delhi in-kind, we are currently selling our oil under the Delhi operator's agreement with Plains Marketing L.P. for the delivery of our oil to a pipeline 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, 2019 and 2018. 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.

	Year Ended June 30,	
Customer	**2019**	**2018**
Plains Marketing L.P. (Oil sales from Delhi)	94%	92%
American Midstream Gas Solutions. L.P. (NGL sales from Delhi)	6%	8%
All others	—%	—%
Total	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. 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").

Note 18 – 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 contributions fully vested when made. Our matching contributions to the Plan totaled $52,809 and $43,134 for the years ended June 30, 2019 and 2018, respectively.

Note 19 – 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 Financial Instruments. The Company's other financial instruments consist of cash, cash equivalents, and restricted cash, receivables and payables. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

Other Fair Value Measurements. The initial measurement and any subsequent revision of asset retirement obligations at fair value are calculated using discounted future cash flows of internally estimated costs. Significant Level 3 inputs used in the calculation of asset retirement obligations include the costs of plugging and abandoning wells, surface restoration and reserve lives. Subsequent to initial recognition, revisions to estimated asset retirement obligations are made when changes occur for input values.

Note 20 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited)

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

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Exploration and development costs also include amounts incurred due to the recognition of asset retirement obligations of $86,384 and $43,922 during the years ended June 30, 2019 and 2018, respectively.

	For the Years Ended June 30,	
	2019	2018
Oil and Natural Gas Activities		
Property acquisition costs:		
Proved property	$ —	$ —
Unproved property (a)	—	—
Exploration costs	—	—
Development costs	5,229,235	5,429,985
Total costs incurred for oil and natural gas activities	$ 5,229,235	$ 5,429,985

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of the net proved oil and natural gas reserves of our oil and gas properties located entirely within the United States of America are based on evaluations prepared by third-party reservoir engineers. Reserve volumes and values were determined under the method prescribed by the SEC for our fiscal years ended June 30, 2019 and 2018, 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 reserve life, when estimating whether reserve 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, 2017	8,372,150	1,686,228	—	10,058,378
Revisions of previous estimates (a)	369,971	(315,090)	—	54,881
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(651,931)	(93,366)	—	(745,297)
June 30, 2018	8,090,190	1,277,772	—	9,367,962
Revisions of previous estimates (b)	152,420	199,078	—	351,498
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(626,879)	(112,089)	—	(738,968)
June 30, 2019	7,615,731	1,364,761	—	8,980,492
Proved developed reserves:				
June 30, 2017	6,617,389	1,332,803	—	7,950,192
June 30, 2018	6,291,850	993,741	—	7,285,591
June 30, 2019	6,273,907	1,124,302	—	7,398,209
Proved undeveloped reserves:				
June 30, 2017	1,754,761	353,425	—	2,108,186
June 30, 2018	1,798,340	284,031	—	2,082,371
June 30, 2019	1,341,824	240,459	—	1,582,283

(a) The positive crude oil revision resulted from better production performance during fiscal 2018. The negative NGL revision results primarily from lower expectations for ultimate NGL recoveries from the plant based on production data subsequent to the commencement of plant production.

(b) The positive crude oil and NGL revisions were the result of improvements in well and NGL plant performance respectively.

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales and production and development costs have been estimated using prices and costs in effect at the end of the years indicated, as required by ASC 932, 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 and asset retirement obligations 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, 2019 and 2018 are as follows:

	As of June 30,	
	2019	2018
Future cash inflows	$ 524,037,200	$ 521,533,765
Future production costs and severance taxes	(208,539,679)	(228,478,119)
Future development costs	(18,395,252)	(22,213,269)
Future income tax expenses	(55,881,997)	(50,810,883)
Future net cash flows	241,220,272	220,031,494
10% annual discount for estimated timing of cash flows	(114,488,230)	(101,073,080)
Standardized measure of discounted future net cash flows	$ 126,732,042	$ 118,958,414

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.

	For the Years Ended June 30,			
	2019		2018	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$ 61.62	n/a	$ 57.50	n/a

There were no natural gas reserves in 2019 and 2018. 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 projected to be produced by the plant.

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

	For the Years Ended June 30,	
	2019	2018
Balance, beginning of the fiscal year	$ 118,958,414	$ 82,937,553
Net changes in sales prices and production costs related to future production	23,753,518	62,011,112
Changes in estimated future development costs	833,494	267,547
Sales of oil and gas produced during the period, net of production costs	(28,962,837)	(29,087,710)
Net change due to extensions, discoveries, and improved recovery	—	—
Net change due to revisions in quantity estimates	6,129,847	888,896
Net change due to sales of minerals in place	—	—
Development costs incurred during the period	2,089,139	—
Accretion of discount	14,604,387	11,089,455
Net change in discounted income taxes	(2,795,183)	871,540
Net changes in timing of production and other	(7,878,737)	(10,019,979)
Balance, end of the fiscal year	$ 126,732,042	$ 118,958,414

Note 21 – Selected Quarterly Financial Data (Unaudited)

The following table presents summarized quarterly financial information for the fiscal years ended June 30, 2019 and 2018:

2019	First (1)	Second	Third	Fourth
Revenues	$ 12,307,079	$ 11,048,118	$ 9,501,028	$ 10,373,396
Operating income	5,994,927	4,733,747	2,952,955	3,955,194
Net income available to common shareholders	$ 5,795,801	$ 3,904,565	$ 2,398,875	$ 3,277,825
Basic net income per share	$ 0.18	$ 0.12	$ 0.07	$ 0.10
Diluted net income per share	$ 0.17	$ 0.12	$ 0.07	$ 0.10

2018	First	Second (2)	Third	Fourth
Revenues	$ 8,537,871	$ 11,066,911	$ 10,249,566	$ 11,426,864
Operating income	2,536,459	4,829,252	3,663,267	5,182,663
Net income available to common shareholders	$ 2,140,532	$ 9,876,848	$ 3,068,354	$ 4,532,750
Basic net income per share	$ 0.06	$ 0.30	$ 0.09	$ 0.14
Diluted net income per share	$ 0.06	$ 0.30	$ 0.09	$ 0.14

(1) The first quarter of fiscal 2019 included other income of $1.1 million for the Enduro transaction breakup fee.

(2) The second quarter of fiscal 2018 was impacted by a $6 million tax benefit attributable to the Tax Cut and Jobs Act enacted during December 2017.

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 interim 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 interim 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 interim 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, 2019.

The effectiveness of our internal control over financial reporting at June 30, 2019 has been audited by Moss Adams 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, 2019 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 2019 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 2019 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 2019 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 2019 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 2019 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:

   Reports of Independent Registered Public Accounting Firm

   Consolidated Balance Sheets

   Consolidated Statements of Operations

   Consolidated Statements of Cash Flows

   Consolidated Statements of Changes in 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 Master 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.

Item 16. Form 10-K Summary

None.

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 12, 2019	By:	/s/ JASON E. BROWN *Jason E. Brown* *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 12, 2019	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 12, 2019	/s/ JASON E. BROWN Jason E. Brown	President and Chief Executive Officer (Principal Executive Officer)
September 12, 2019	/s/ DAVID JOE David Joe	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
September 12, 2019	/s/ R. STEVEN HICKS R. Steven Hicks	Senior Vice President, Engineering and Business Development
September 12, 2019	/s/ RODERICK SCHULTZ Roderick Schultz	Vice President, Chief Accounting Officer (Principal Accounting Officer)
September 12, 2019	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 12, 2019	/s/ WILLIAM DOZIER William Dozier	Director
September 12, 2019	/s/ KELLY W. LOYD Kelly W. Loyd	Director
September 12, 2019	/s/ MARRAN J. OGILVIE Marran J. Ogilvie	Director

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	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	2004 Stock Plan (previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14C on August 9, 2004)
4.3	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)
4.4	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)
4.5	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)
4.6	Form of Restricted Stock Agreement (previously filed as an exhibit to Form SC TO-I on May 15, 2009)
4.7	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)
4.8	2016 Equity Incentive Plan (previously filed as an exhibit to the Company's Form 10-Q on February 8, 2017)
4.9	Majority Voting Policy for Directors (previously filed as an exhibit to the Company's Current Report on Form 8-K on October 31, 2012)
4.10	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan (previously filed as an exhibit to Form 10-Q on February 8, 2018)
4.11	Form of Contingent Restricted Stock Agreement under 2016 Equity Incentive Plan (previously filed as an exhibit to Form 10-Q on February 8, 2018)
4.12	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (filed herein)
4.13	Form of Performance Share Unit Award Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (filed herein)
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)
10.8	First Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and Midfirst Bank effective October 18, 2016 (previously filed as an exhibit to Form 10-Q on November 9, 2016)
10.9	Second Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and Midfirst Bank effective February 1, 2018 (previously filed as an exhibit to Form 10-Q on February 8, 2018)

EXHIBIT NUMBER	DESCRIPTION
10.10	Third Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and Midfirst Bank effective May 25, 2018 (previously filed on September 10, 2018 as an exhibit to Form 10-K)
10.11	Fourth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and Midfirst Bank effective December 31, 2018 (previously filed on February 8, 2019 as an exhibit to Form 10-Q)
10.12	Employment Offer Letter to Jason E. Brown dated July 8, 2019 (filed herein)
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 Moss Adams LLP (filed herein)
23.2	Consent of DeGolyer & MacNaughton (filed herein)
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, 2019, on oil and gas reserves (SEC Case) dated August 2, 2019 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