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, 2020

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

For the transition period from to

Commission File Number 001-32942

EVOLUTION PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

Title of Each Class	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 every Interactive Data File required to be submitted 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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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, 2019, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $5.47 on the NYSE American was $122,253,472.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 1, 2020, was 32,956,469.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2020 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

2020 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 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 INDUSTRY TERMS

Term	Definition
Bbls	Barrels of oil or natural gas liquids.
BFPD	Barrels of fluid per day.
BOE	Barrels of oil equivalent. BOE is calculated by converting 6 MCF of natural gas to 1 Bbl of oil which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.
BOPD	Barrels of oil per day.
BTU	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; CO_2 is a gas that can be found in naturally occurring reservoirs, is typically associated with ancient volcanoes, is a major byproduct from manufacturing and power production, and is 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 a means not involving a well.
EOR	Enhanced Oil Recovery; projects that 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 within or related to the same geologic structural features and/or stratigraphic features.*
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 which potentially increases 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.
MMBOE	One million barrels of oil equivalent.
MMBTU	One million British Thermal Units.
MMCE	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; 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 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(d), or any metric derivation thereof, such as a millidarcy(md), where one darcy equals 1,000 millidarcys. Extremely low permeability of 10 millidarcys, or less, are often associated with source rocks, such as shale. Extraction of hydrocarbons from a source rock is more difficult than a sandstone reservoir where permeability typically ranges one to two darcys or more.
Porosity	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.
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 a means not involving a well.
Proved Developed Nonproducing Reserves	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 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 are 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.

* 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 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 our interests in the Hamilton Dome field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir, and overriding royalty interests in two onshore Texas wells.

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

On November 1, 2019, the Company acquired non-operated working interests in the Hamilton Dome field consisting of a 23.5% working interest, with an associated 19.7% revenue interest (inclusive of a small overriding royalty interest). The field is operated by Merit Energy Company ("Merit"), a private oil and gas company, who owns the vast majority of the remaining working interest in Hamilton Dome field. Our acquired interest in Hamilton Dome aligned with the Company's strategy of adding long lived, low decline reserves expected to be supportive of our dividend over the long-term.

Significant Activity in Fiscal 2020

- Proved oil equivalent reserves at June 30, 2020 were 10.2 MMBOE, a 13% increase from the previous year primarily due to the acquisition of the Hamilton Dome field in November 2019. The Standardized Measure for proved reserves decreased 51% to $62 million, as the acquisition of the Hamilton Dome field was offset by the decrease in the average first day of the month net oil price from $64.54 per barrel of oil and $23.83 per barrel of natural gas liquids at June 30, 2019 to $46.37 per barrel of oil and $9.00 per barrel of natural gas liquids at June 30, 2020. Our proved reserves consist of 80% crude oil and 20% natural gas liquids, 82% are classified as proved developed producing and 18% are proved undeveloped.

- We recognized net income of $5.9 million, or $0.18 per diluted common share, our ninth consecutive year of reporting net income.

- Returned to shareholders $10.7 million in cash dividends and $2.5 million in stock repurchases in fiscal 2020. The Company has paid out to shareholders more than $70 million in cash dividends since inception of the dividend program in December 2013.

- Closed the acquisition of non-operating working interest in the Hamilton Dome field on November 1, 2019 which included total proved reserves of 1.47 MMBOE as of June 30, 2020 as estimated by DeGolyer & MacNaughton ("D&M"), an independent reservoir engineering firm.

- Reported $12.4 million of cash flows from operations for the fiscal year ended June 30, 2020. We funded all operations, including $11.8 million of capital spending inclusive of our $9.3 million acquisition of our interest in the Hamilton Dome Field, from internal resources and remain debt free at June 30, 2020.

- In order to mitigate the impact of the growing global COVID-19 pandemic on our employees, we continue to follow local stay-at-home orders and remotely work from home with minimal disruptions to our business operations.

- We entered into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020 at a fixed swap price of $32.00 per barrel, recording a loss of $1.4 million at June 30, 2020. Of this amount, $1.9 million were non-cash, unrealized mark-to-market losses as commodity prices improved from those existing at fiscal year-end, offset in part by $0.5 million in realized gains during the fiscal fourth quarter.

- We completed remaining capital expenditures for the six-well water curtain program and related infrastructure preceding the planned Delhi Phase V development, which was delayed by the operator until our fiscal fourth quarter of 2021.
- In July 2020, Denbury Resources announced that it had entered into a restructuring support agreement with certain of its debt holders and filed a pre-packaged voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in Texas. Denbury Resources is seeking to eliminate $2.1 billion of debt. Denbury subsequently announced on September 3, 2020 that its plan to eliminate $2.1 billion of its bond debt has been confirmed by the court which will substantially reduce its debt and strengthen its balance sheet.

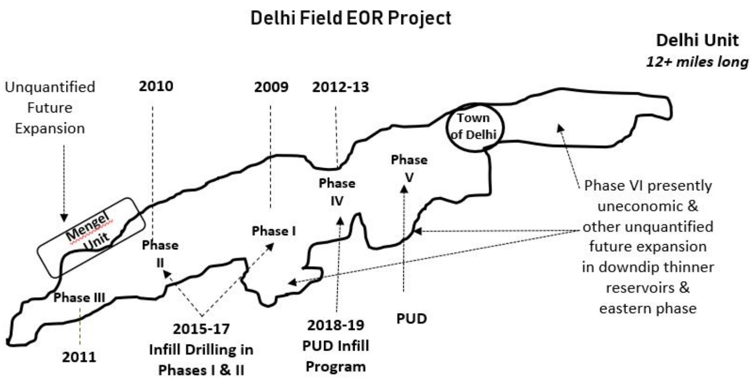
Our Reserves: Delhi Field - Enhanced Oil Recovery - Onshore Louisiana

Our independent reservoir engineering firm, D&M, assigned the estimated reserves net to our interests at Delhi as of June 30, 2020; we had 8.7 million bbls of total proved oil equivalent reserves. The following table summarizes the reserves assigned by D&M:

	Reserves as of June 30, 2020
	Proved
Reserves MBOE	8,746
% Developed	79%
Liquids %	100%

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

Our working and royalty interests in the Delhi field is currently our largest producing asset. The Holt-Bryant Unit ("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 Denbury 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 21.5 million bbls of oil.



After the May 2006 conveyance, Denbury as the operator, originally planned six primary phases for the installation of the CO_2 flood in the Delhi field. Four of these six phases have been completed as of June 30, 2020 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 (Phase VI) was removed from proved reserves 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 initially installed and subsequently expanded during calendar 2011. First oil production response from Phase III occurred during June 2011, and field gross production subsequently increased to more than 5,000 gross barrels of oil per day by December 2011.

Phase IV was 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. First oil production response from Phase IV occurred during August 2012, and field gross production increased to more than 7,500 gross barrels of oil per day by February 2013.

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, has isolated that part of the field with a water curtain, thus removing the area from the CO_2 flood.

Construction began on the NGL extraction plant in February 2015 and 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 extraction plant are used to generate electrical power for 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. To date, we have incurred a net capital cost of approximately $27.4 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 significantly reduced capital spending as a result of declining oil prices. Resumption of this work has been delayed due to low prevailing oil prices and the operator's 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.

An infill drilling program commenced in March 2018 to target productive oil zones in the developed areas of the field that were not being swept efficiently by the CO_2 flood.During fiscal 2019 the 12 well infill program, consisting of 10 producing wells and two CO_2 injection wells, was completed. Proved undeveloped reserves of 536 MBOE were converted to proved developed reserves.

Additionally during fiscal 2019, 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 injection well followed by three injection wells in fiscal 2018. During fiscal 2019, the operator drilled the two remaining injection wells and proceeded with completions and injection line work. The first pad commenced operations during fiscal 2019 and the second pad began injections during our second quarter of fiscal 2020.

At June 30, 2020, we had total proved reserves of 8.7 MMBOE at Delhi, which was comprised of 6.7 MMBOE of oil and 2.0 MMBOE of NGLs as estimated by our independent petroleum engineering firm. The following table sets forth our estimated proved reserves as of June 30, 2020. For additional reserve information see Note 21 to our consolidated financial statements in Item 8.

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)*
PROVED			
Developed Producing (79% of Proved)	5,105	1,777	6,882
Undeveloped (21% of Proved)	1,648	216	1,864
TOTAL PROVED	6,753	1,993	8,746
Product Mix	77%	23%	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 which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

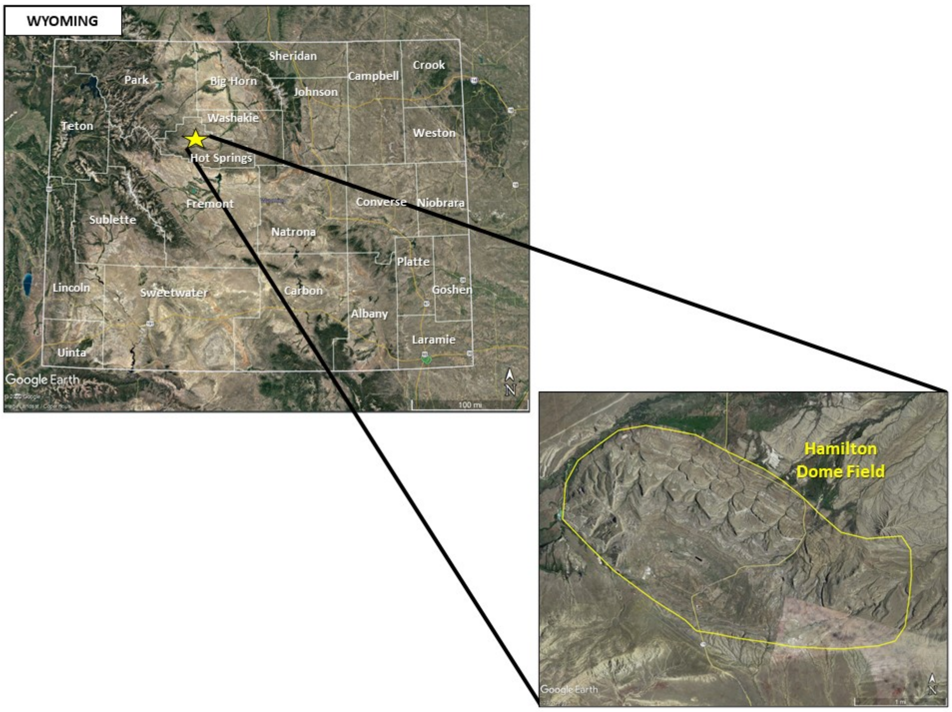
For fiscal 2020, average gross daily oil production at Delhi was 5,632 BOPD and 1,106 bbls NGLs per day (6,738 BOEPD). The total gross purchased CO_2 volume was 19 BCF for fiscal 2020. In February 2020, the CO_2 purchase line to Delhi was shut-in by the pipeline operator for extensive repairs. No CO_2 was purchased from the shut-in date through June 2020. The recycle facilities continue to operate as usual providing approximately 80% of the injected CO_2 volumes to Delhi with production somewhat reduced due to lower injection volumes. Per communications with Denbury, the CO_2 line is currently being repaired and is projected to be completed early in the second quarter of our fiscal 2021.

Our Reserves: Hamilton Dome - Hot Springs County, Wyoming

Our independent reservoir engineering firm, D&M, assigned the estimated reserves net to our interests at Hamilton Dome as of June 30, 2020; we had 1.5 million bbls of total proved oil equivalent reserves. The following table summarizes the reserves assigned by D&M:

	Reserves as of June 30, 2020
	Proved
Reserves MBOE	1,473
% Developed	100%
Liquids %	100%

On November 1, 2019, the Company acquired certain mineral interests in the Hamilton Dome field from Merit, who owns the vast majority of the remaining working interest in the field. The Hamilton Dome field is located in the southwest part of the Big Horn Basin in northwest Wyoming about twenty miles northwest of Thermopolis in Hot Springs County.



Our interest includes a 23.5% working interest and an associated 19.7% revenue interest (inclusive of a small overriding royalty interest). The Hamilton Dome field has produced over 160 MMBO over the last 100 years; Merit has operated the field over the last 25 years. Production from this field is 100% oil and is currently averaging low single-digit decline rates.

Development History of the Hamilton Dome Field - Hot Springs County, Wyoming

Oil was first discovered at the Hamilton Dome field within the Big Horn Basin in September 1918 in the Curtis/Chugwater reservoir by New York Oil Company via surface mapping. Shortly thereafter, the Phosphoria and Tensleep formations were discovered in 1919 and 1929, respectively. The field is part of an anticlinal fold with a southerly bounding fault with approximately 4,500-5,000 feet of displacement, thus providing a structural trap. The two major producing formations are the Tensleep (sandstone) and Phospohoria (limestone) reservoirs. Additional present day and historical production exists from the Curtis/Chugwater (sandstone), Amsden (sandstone), Madison (limestone), and Big Horn (dolomite) formations. These formations produce from depths ranging approximately 1,500 to 3,600 feet and have historically produced at rates of greater than 25,000 gross BOPD. The productive surface area of the field spans approximately 2,500 acres. The original oil in place of the six producing reservoirs is estimated to be at least 500 million barrels. Over the last 100 years, more than 160 million barrels have been produced from the field.

Although the Tensleep reservoir was discovered in 1929, it remained largely undeveloped until World War II. Active development of the Tensleep reservoir occurred between 1944 and 1960. The Madison and Darwin reservoirs were discovered in 1948 and 1959, respectively. These two reservoirs were developed sporadically from 1950 through the 1970’s. In 1970, 52 years after the field’s discovery, a waterflood was implemented in the Curtis/Chugwater reservoir. In 1973, the Phosphoria reservoir was unitized in order to implement a waterflood of the reservoir, this unit is still in place and is approximately 3,160 acres. In the early 1970’s, Tensleep production was down spaced to 5 acres and in the late 1970’s an isolated Tensleep waterflood was implemented. By 1981, the Tensleep reservoir had produced more than 147 million bbls. The last active development of the Curtis/Chugwater reservoir occurred in 1978 when the waterflood was ended. The Madison reservoir was further developed in the early 1990’s.

Merit Energy purchased the field in 1995 and has operated the field for 25 years; the field was unitized in 1996. The Phosphoria and Tensleep reservoirs were permitted for unlimited commingling in 1996 as well. In 1997, Merit began a capital workover program to downspace the Phosphoria reservoir to 10 acres in addition to improving the Tensleep and Phosphoria waterfloods and eliminating commingled production.

Under Merit’s operations, the wells in the Hamilton Dome field are produced via electric submersible pumps (ESP) and rod pumps. Typical workovers in the field include rod repair, ESP repair, injector acid jobs, and wellbore cleanouts.

At June 30, 2020, EPM has total net proved reserves of 1.47 MMBOE at Hamilton Dome which was entirely comprised of oil as estimated by our independent reservoir engineering firm. The following table sets forth our estimated proved reserves as of June 30, 2020 for our Hamilton Dome field. For additional reserve information see Note 21 to our consolidated financial statements in Item 8.

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)*
PROVED			
Developed Producing (100% of Proved)	1,473	—	1,473
Undeveloped (0% of Proved)	—	—	—
TOTAL PROVED	1,473	—	1,473
Product Mix	100%	—%	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 which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Following acquisition in November 2019, average gross daily production was 2,048 BOPD through the end of fiscal 2020. From March to June 2020, the production rate was negatively impacted by an estimated 870 gross BOPD, or approximately 38%, due to the shut-in of 61 wells as a result of the drop in oil prices.

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.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2020

Our proved reserves at June 30, 2020, 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 reservoir engineer, DeGolyer and MacNaughton which was formed in 1936. D&M has completed more than 23,000 projects in more than 100 countries. D&M was selected to estimate reserves primarily 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 reserves as of June 30, 2020. For additional reserve information see Note 21 to our consolidated financial statements in Item 8. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $47.37 per barrel of crude oil. The net price per barrel of NGLs was $9.00, 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 geographic 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, 2020

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)*
PROVED			
Developed Producing (82% of Proved)	6,578	1,777	8,355
Undeveloped (18% of Proved)	1,648	216	1,864
TOTAL PROVED	8,226	1,993	10,219
Product Mix	80%	20%	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 which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

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The following table presents a reconciliation of changes in our proved reserves by major property, on the basis of equivalent MBOE quantities.

Reconciliation of Changes in Proved Reserves by Major Property

	Delhi Field Proved Total
Proved reserves, MBOE	MBOE
June 30, 2019	8,981
Purchases	—
Production	(647)
Revisions (a)	412
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2020	8,746

(a) Positive revisions of 412 MBOE at Delhi field reflect adjusted methodology of forecasting NGLs independently from the oil production forecast by our independent reservoir engineering firm.

	Hamilton Dome Field Proved Total
Proved reserves, MBOE	MBOE
June 30, 2019	—
Purchases	3,427
Production	(98)
Revisions (a)	(1,856)
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2020	1,473

(a) Negative revisions of 1,856 MBOE were due to the impacts of lower oil prices since the field’s November 2019 acquisition and to subsequent reduced rates of production. Responding to lower oil prices, in March, the operator shut in wells that were not economic to optimize the field's cash flow. Although some returned to production as prices improved, as of June 30, 2020, approximately 25% of the wells remained shut-in. The lowered historical production curve and lower SEC average price, resulted in the field reaching its economic limit sooner than it had when proved reserves were estimated at the acquisition date.

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 President and Chief Executive Officer, Jason Brown, who 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. Such reserves estimates are in compliance with generally accepted petroleum engineering and evaluation principles, definitions, and guidelines as established by the SEC.

The reserves information in this filing is based on estimates prepared by D&M, our independent petroleum engineering firm, which was formed in 1936 and has completed more than 23,000 projects in more than 100 countries. The person responsible for preparing the reserves report with D&M is a Registered Professional Engineer in the State of Texas and a 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.

We provide D&M with our property interests, production, current operating costs, current production prices and other information in order to prepare the reserve estimates. This information is reviewed by our President and Chief Executive Officer, designated operations personnel, and other members of management to ensure accuracy and completeness of the data prior to submission to D&M. The scope and results of D&M'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 1,864 MBOE at June 30, 2020, with associated future development costs of approximately $8.6 million, which are associated with the Phase V development of Delhi field. The Company does not have any proved undeveloped reserves associated with its Hamilton Dome field acquired in November of 2019.

During the year ended June 30, 2020 our proved undeveloped reserves changed as follows:

	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)
June 30, 2019	1,342	241	1,583
Revisions to previous estimates	306	(25)	281
Conversion to proved developed reserves	—	—	—
June 30, 2020	1,648	216	1,864

Price declines resulted in a reclassification of a small volume of oil reserves from PDP to PUD at June 30, 2020. The decline in price led to currently producing wells becoming uneconomic at an earlier point in time than previously estimated. However, when forecasted in conjunction with the PUD reserves the overall economic life of the field is extended. Due to the EOR unit nature of Delhi, this PDP reduction shifts those reserves to our PUD oil reserves as they are considered proved and expected to be recovered as a result of the development of our Phase V. NGL reserves were revised downward 25 MBbls primarily due to the adjusted methodology of projecting NGL volumes independent of oil production, shifting them into developed NGL volumes. 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 this project's inception in March 2018, its net capital expenditures have totaled $4.6 million.

The initial assignment of proved undeveloped reserves in the Delhi field was made on June 30, 2010, which encompassed a large scale CO_2 enhanced oil recovery project. The operator's development plans for the field have remained essentially unchanged and were originally scheduled to be completed by June 30, 2015, within five years from the initial recording of such proved reserves. 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 $3.7 million as of June 30, 2020, including $0.6 million and $1.6 million in fiscal years 2020 and 2019, respectively, on the six well water curtain program and related infrastructure required to precede the development of Phase V. As of June 30, 2020 we had drilled all the injection wells, including four gross injection wells during fiscal 2019, and commenced operations for one of the program's pads. The program was configured as two pads, each having two injection wells and one water source well. The second pad was completed during fiscal 2020 and began injections during our second quarter of fiscal 2020.

As of June 30, 2020, 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 May 2021 based on our discussions with the operator. The timing of Phase V development 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 four fiscal years. We have been continuously developing the Delhi field and have spent over $48 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, 2020, no proved 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 proved 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 any proved reserves associated with our 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, 2020		Year Ended June 30, 2019		Year Ended June 30, 2018	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Crude oil (Bbls)	638,464	$ 44.76	626,879	$ 65.05	651,931	$ 58.52
Natural gas liquids (Bbls)	106,159	$ 9.59	112,013	$ 21.87	93,366	$ 28.06
Natural gas (Mcf)	1,087	$ 1.90	459	$ 2.64	—	$ —
Average price per BOE*	744,804	$ 39.74	738,968	$ 58.50	745,297	$ 54.71
Production costs	**Amount**	**per BOE**	**Amount**	**per BOE**	**Amount**	**per BOE**
Production costs, excluding ad valorem and production taxes	$ 12,966,923	$ 17.41	$ 14,027,461	$ 18.98	$ 11,497,759	$ 15.43
Total production costs, including ad valorem and production taxes	$ 13,505,502	$ 18.13	$ 14,266,784	$ 19.31	$ 11,685,817	$ 15.68

*Equivalent oil reserves are defined as six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Drilling Activity

Our productive drilling activity during the past three fiscal years at Delhi field ended June 30, 2020, and 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. 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 drilled three (0.72 net) wells and in fiscal 2017 one (0.239 net) well was drilled. A pad consists of one gross water source well and two gross water injector wells. The three completed wells comprise the northern pad of the water curtain program which commenced injection during fiscal 2019. The southern pad became fully operational late in the second quarter of fiscal 2020 when capital expenditures for completion work concluded.

Hamilton Dome field is considered fully developed. No wells were drilled in fiscal 2020 and there are no plans to drill wells in fiscal 2021.

Present Activities

The operator is completing a SCADA (supervisory control and data acquisition) well monitoring capital project at present which will improve the flow of information and assist in the real-time management of the Delhi field. There are no significant drilling plans until Phase V development, expected to commence in the fourth quarter of fiscal 2021.

For further discussion, see "Highlights for our fiscal year 2020" and "Capital Expenditures" within Item 7.

Delivery Commitments

As of June 30, 2020, 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.

If the price of oil remains above $32.00, we have a financial commitment as we entered into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020 at a fixed swap price of $32.00 per barrel.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we own a working interest as of June 30, 2020.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	—	—	315	74.5	315	74.5
Natural gas	—	—	—	—	—	—
Total	—	—	315	74.5	315	74.5

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2020. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would allow 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 (1)	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Delhi Field, Louisiana (2)	9,126	2,180	4,510	1,077	13,636	3,257
Hamilton Dome Field, Wyoming	5,908	1,389	—	—	5,908	1,389
Total	15,034	3,569	4,510	1,077	19,544	4,646

(1) All acreage, including any undeveloped, nonproductive or undrilled acreage, is held by existing production as long as continuous production is maintained in the unit.

(2) This table excludes acreage attributable to small overriding royalty interests retained in various formations in the Texas Giddings Field area. Except for de minimis production that began on two leases during later 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 per the State of Louisiana Department of Conservation order number 96-G-5, all acreage, including any undeveloped, nonproductive or undrilled acreage is held by existing production as long as continuous production is maintained in the unit.

When the Company acquired Hamilton Dome field on November, 1 2019, the field had been fully developed through primary recovery and all acreage is reflected as developed acreage. The Tensleep and Phosphoria were permitted for commingling and unitized in 1996 following purchase of the field by Merit Energy. The Company estimates that our developed acreage includes 5,908 gross (1,389 net) acres in the Hamilton Dome field, with no acres attributable as undeveloped. We own 23.5% working interest in the field, along with a small overriding royalty interest. As Hamilton Dome is unitized, all acreage is held by existing production as long as continuous production is maintained in the unit. We are not operators of Hamilton Dome field.

For more complete information regarding current year activities, including crude oil and natural gas production, refer to Item 7.

Markets and Customers

Our production is marketed to third parties in a manner consistent with industry practices. In the United States of America 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 nor from Hamilton Dome separately from the operators' shares of production. Although we have the right to take our working interest production in-kind, we are currently selling our production through the field operators pursuant to the delivery and pricing terms of their sales contracts. Under such arrangements we typically do not know the identity of the buyers of production except in the case of the Delhi field where there is a sole buyer for oil and another for NGL's.

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 $0.77 per barrel during our fiscal year ended June 30, 2020, compared to $4.11 per barrel for the prior year. In the current fiscal year, the differential was impacted by market conditions over the second half of the fiscal year and trucking charges that were incurred for several months while the sales pipeline underwent repair. NGL production is sold to a midstream processing company which fractionates the stream and sells the resulting hydrocarbons.

On November 1, 2019, Evolution acquired a non-operated interest in the Hamilton Dome field in Wyoming. All the field’s production is sour heavy crude oil which is the sole component of the field’s reserves. Crude oil is transported by pipeline primarily to purchasers in Casper, Wyoming. As a result of transportation differentials, the high sulfur content and low API gravity, this crude trades at a discount to WTI, averaging $17.62 lower over the last eight months. Although we have the option of taking our production in kind, we have elected to have the operator market our share of production. Our realized price is net of transportation and marketing costs.

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

	Year Ended June 30,	
Customer	**2020**	**2019**
Plains Marketing L.P. (Delhi field oil)	87%	94%
Merit Energy Company (Hamilton Dome field oil)	10%	—%
Third Coast Midstream (Delhi field NGLs)	3%	6%
All others	—%	—%
Total	100%	100%

The loss of a purchaser at either the Delhi or Hamilton Dome fields or disruption to pipeline transportation from these fields could adversely affect our net realized pricing and potentially our near-term production levels.

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.

Oil prices over the past few years have fluctuated and been extremely volatile. For example, average daily prices for WTI crude oil ranged from a high of $74 per barrel to a low of a negative $38 per barrel over our past few fiscal years. Starting in the fourth quarter of 2014, the price of oil per barrel dropped dramatically and continuing into 2017 before recovering somewhat in late calendar 2018, then weakening again in 2019 and dropping substantially in 2020 as a result of the impact of the COVID-19 pandemic and geopolitical factors. Worldwide factors such as global health pandemics, 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.

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, 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. 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 areas and geological systems and the abilities to efficiently conduct operations, achieve technological advantages, identify, and acquire economically producible reserves and obtain capital at rates which allow economic investments.

Risk Management

Derivative instruments are occasionally utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. We have designed a risk management policy to use derivative instruments from time to time during periods of extraordinary price volatility and when such instruments are needed to ensure the Company can meet its current dividend policy, fund its capital expenditures commitments and maintain liquidity. We determine the duration of derivative positions to approximate the anticipated period of volatility and the percentage of our production to be hedged, based on our view of current and future market conditions. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivatives available, we typically use fixed-price swap and costless collars to attempt to manage price risk. The fixed-price swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the fixed-price swap agreement. Costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the settlement price under the agreement exceeds the ceiling and payments from the counterparties if the settlement price under the agreement is below the floor.

We entered into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020 at a fixed swap price of $32.00 per barrel. In the future we may add additional swaps or other derivative positions covering a variable portion of our anticipated future production during subsequent periods.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. As of June 30, 2020, we did not post collateral under any of our derivative contracts as they are uncollateralized trades. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A and Note 19 to our consolidated financial statements in Item 8 for additional information.

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 environment is often difficult and costly; substantial penalties may be incurred for noncompliance. To the best of our knowledge, we are in compliance with all federal and state-level laws and regulations applicable to our operations. 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. We do not currently anticipate that continued and future compliance with existing laws and regulations will have a materially adverse effect on our consolidated financial position or results of operations.

See discussion captioned "Government regulation and liability for oil and gas operations and environmental matters may adversely affect our business and results of operations" in Item 1A.

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 and 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, 2020, 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.

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 a negative $38 per barrel over our past few fiscal years. 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:

- changes in global supply and demand for oil and natural gas, which has recently been negatively affected by concerns about the impact of COVID-19;
- 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 affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-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 80% of our proved reserves at June 30, 2020 are crude oil reserves and 20% 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 two assets 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.

Our revenues come from our royalty, mineral and working interests in the Delhi field in Louisiana and the Hamilton Dome field in Wyoming and thus our current revenues are highly concentrated in these fields. Any significant downturn in production, oil and NGL prices, or other events beyond our control which impact these fields could have a material adverse effect on our results of operations and financial results. We are not the operator of these fields, 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 and our newly acquired interests in the

Hamilton Dome field in Wyoming. Environmental or operating problems or lack of extended future investment in either of these fields 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. In fiscal 2020, our production was impacted by the operators of both fields. Delhi production volumes were negatively impacted as a result of the financial strain Denbury was under and their lack of investment in projects in the field, including the delay of our Phase V, in addition to the purchased CO_2 line being shut in for repairs. In the Hamilton Dome field Merit temporarily shut in a portion of the production as it was uneconomic at the historically low prices. As of June 30, 2020, a number of these wells have returned to production and we continue to monitor their performance; however, there is no guarantee that prolonged periods of being shut in or lack of investment would not negatively impact future production.

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 operators with respect to the successful operation of our principal assets, which consists of our interests Delhi and Hamilton Dome fields. A materially negative change in our operator's financial condition could negatively affect operations (or timing thereof) in these fields, and consequently our income (or timing thereof) from these fields as well as the value of our interests in these fields.

Our royalty, mineral and working interests in the Delhi field, located in Northeast Louisiana are our primary producing assets. Approximately 90% of our revenues come from the Delhi 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.

On February 22, 2020, DNR experienced a pressure loss in its CO_2 purchase pipeline resulting in an immediate shut down. DNR cut out a section of the failed pipeline and sent it out for analysis on the cause of the failure and remediation procedures. Analysis results, with the consultation the government regulating agency, recommended repairing the damaged section of pipeline. DNR has informed the Company that preparations for this project are underway and the CO_2 purchases line should be back in operation October 1, 2020.

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.

In July 2020, Denbury announced that it had entered into a Restructuring Support Agreement (the "RSA") with holders of 100% of revolving credit facility loans, approximately 67.2% of second lien notes and approximately 70.8% of convertible notes for a "pre-packaged" plan to eliminate $2.1 billion of bond debt and subsequently filed for voluntarily filed petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas. Denbury subsequently announced on September 3rd that its plan to eliminate $2.1 billion of its bond debt has been confirmed by the court which will substantially reduce its debt, strengthen its balance sheet, and position Denbury to free up capital for investment in properties such as Delhi again.

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 and Hamilton Dome assets are productive from relatively shallow reservoirs; we may pursue assets that produce from deeper reservoirs in the future. 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 cost and 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 produce 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 which 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. The risk that no commercially productive crude oil or natural gas reservoirs will be encountered is paramount. The cost of drilling, completing and operating wells is substantial and uncertain; 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 reservoir formations;
- equipment failures or accidents;
- regulatory climate;
- 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, 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 guarantee that our overall drilling success rate 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, 2020, one purchaser accounted for approximately 87% of our total oil revenues. We do not currently market our share of crude oil production from the Delhi or Hamilton Dome fields. Although we have the right to take our working interest production in-kind, we are currently accepting terms under the operators' agreements for the delivery and pricing of our oil. The loss of a large purchaser for our oil production could negatively impact the revenue we receive. We cannot guarantee that we could readily find other purchasers for our oil and natural gas production. In addition, the crude oil production from the Delhi and Hamilton Dome fields is transported by pipeline; if either of these pipelines 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 inherent uncertainties. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot always be measured in an exact manner. Estimates of economically recoverable crude oil and natural gas reserves depend upon a number of variable factors. These factors include historical production from the area compared with production from other comparable producing areas, 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, work-over costs, and remedial costs. Some or all of these assumptions utilized in estimating reserve volumes may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of reserves, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected from reserves may vary substantially depending on the timing ang and different engineers preparing reserves estimates.

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; 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. Interest rates in effect vary from time to time based on risks associated with us or the oil and natural gas industry in general. The Standardized Measure does not necessarily correspond to market value.

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

On a periodic basis we review the carrying value of our crude oil and natural gas properties under the applicable rules of 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 of 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, 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. Derivative arrangements may include 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.

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 portions of our undeveloped leasehold acreage may be subject to expiration 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 will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult and may involve unexpected costs or delays.

We periodically evaluate acquisitions of reserves, properties, prospects, 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, integrating significant acquisitions, and strategic transactions in concert with the Company's ongoing business demands;
- the challenge and cost of integrating acquired operations, information management, 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 may 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, 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 from 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 from 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 operators, vendors, suppliers, customers and other business partners may become the target of cyber attacks or information security breaches. Cyber attacks or information security breaches 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 of America and abroad. Computers are necessary to transport our oil and gas 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 United States of America 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 one or more key personnel 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 oil and gas 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, resulting in 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 redevelopment 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, 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, 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. We may not be able to successfully conduct our operations, evaluate and select suitable properties, or 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. This could result in a reduction or elimination of the revenue received by us from such properties.

Events outside of our control, including a pandemic or broad outbreak of an infectious disease, such as the ongoing global outbreak of a novel strain of the coronavirus identified in late 2019 ("COVID-19"), may materially adversely affect our business.

We face risks related to pandemics, outbreaks, or other public health events that are outside of our control and could significantly disrupt our operations and adversely affect out financial condition. In December 2019, a novel strain of a coronavirus, COVID-19, was identified in Wuhan, China. This virus continues to spread globally including in the United States of America. These and other actions could, among other things, impact the ability of our employees and contractors to perform their duties, cause increased technology and security risk due to extended and company-wide telecommuting and lead to disruptions in our permitting activities and critical business relationships.Additionally, the COVID-19 outbreak and governmental restrictions have significantly impacted economic activity and markets and have dramatically reduced current and anticipated demand for oil and natural gas, adversely impacting the prices we receive for our production. The severity and duration of the current COVID-19 outbreak and the potential for future outbreaks are uncertain and difficult to predict.

The extent to which COVID-19 impacts our business will depend on future developments, which are highly uncertain and cannot be predicted, including new information which may emerge concerning the severity of the coronavirus and the actions to contain the coronavirus or treat its impact, among others. We are unable to predict the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments, including the length of time that the pandemic continues, its ongoing effect on the demand for oil and natural gas and the response of the overall economy and the financial markets after governmental restrictions are eased.

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 United States of America 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 of America or abroad remain prolonged, demand for petroleum products could diminish or stagnate, and production costs could increase. These situations 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, 2020, our stock price as traded on the NYSE American ranged from $2.16 to $7.05. 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.

Significant ownership of our common stock is concentrated in a small number of shareholders who may be able to affect the outcome of the election of our directors and all other matters submitted to our stockholders for approval.

As of June 30, 2020 our executive officers and directors, in the aggregate, beneficially owned approximately 2.7 million shares, or approximately 8.2% of our beneficial common stock base. Blackrock Fund Advisors, et al controlled approximately 3.4 million shares or approximately 10.2% of our outstanding common stock, Arrowmark Colorado Holdings, LLC controlled approximately 2.6 million shares or approximately 7.8% of our outstanding common stock, Renaissance Technologies, LLC controlled approximately 2.4 million shares or approximately 7.3% of our outstanding common stock, Advisory Research, Inc controlled approximately 1.5 million shares or approximately 4.5% of our outstanding common stock and JVL Advisors, LLC controlled approximately 1.5 million shares or approximately 4.5% of our outstanding common stock. As a result, any of these holders could potentially exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover, or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

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

Our common stock trades on the NYSE American. Our trading volumes decreased slightly in fiscal 2020 compared to fiscal 2019. Trading volume in our common stock is relatively low compared to larger companies. During the fiscal year ended June 30, 2020, the daily trading volume in our common stock ranged from a low of 42,300 shares to a high of 931,500 shares, with average daily trading volume of 155,610 shares compared to average daily volume of 180,353 in fiscal 2019. 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.

Payment of dividends on our common stock has been in the past, and could be in the future, reduced or eliminated.

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, our 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. Although it is our intent to maintain a steady dividend for our shareholders, there is no guarantee that we will be able to do so. For example, during the 3rd quarter of fiscal 2020, we reduced our quarterly dividend from $0.10 per common share to $0.025 per common share. 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 above and in Note 6 to our consolidated financial statements in Item 8, which information is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 16 to our consolidated financial statements in Item 8 for a description of any 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, 2020 and 2019, the high and low sales prices for EPM as reported by the NYSE American.

NYSE American: EPM

2020:	High	Low
Fourth quarter ended June 30, 2020	$ 3.20	$ 2.23
Third quarter ended March 31, 2020	$ 5.62	$ 2.16
Second quarter ended December 31, 2019	$ 5.86	$ 5.08
First quarter ended September 30, 2019	$ 7.05	$ 5.55

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

Shares Outstanding and Holders

As of June 30, 2020, there were 32,956,469 shares of common stock issued and outstanding. As of September 1, 2020, there were approximately 213 registered shareholders of our common stock.

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,	
	2020	2019
Fourth quarter ended June 30,	$0.025	$0.100
Third quarter ended March 31,	$0.100	$0.100
Second quarter ended December 31,	$0.100	$0.100
First quarter ended September 30,	$0.100	$0.100

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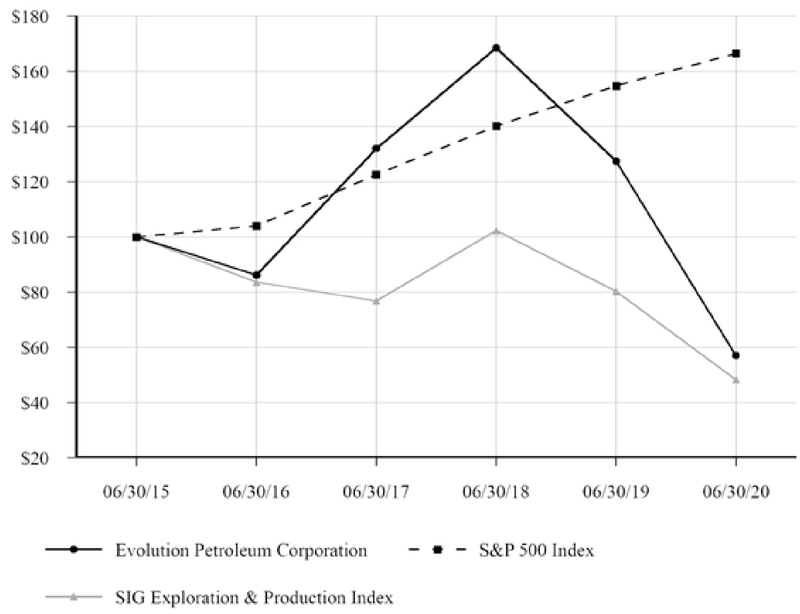
As of June 30, 2020, we have paid 27 consecutive quarterly dividends on our common stock. In August 2020, the Company declared a $0.025 per share dividend payable on September 30, 2020. Any future determination with regard to the payment of dividends will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, results of operations, applicable dividend restrictions, 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, 2015 to June 30, 2020 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, 2015 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	—		$ —	
Outstanding contingent rights to shares	200,000	(1)	—	
Total	200,000		$ —	390,489
Equity compensation plans not approved by security holders	—		—	—
Total	**200,000**		**$ —**	**390,489**

(1) In December 2016, the Company adopted the Equity Incentive Plan (the "2016 Plan"), which authorized the issuance of 1,100,000 shares of common stock. As of June 30, 2020, the Company has granted 709,511 awards under the 2016 Plan and 390,489 shares of common stock remain available for future grants.

Issuer Purchases of Equity Securities

During the fourth quarter ended June 30, 2020, the Company did not purchase any common stock in the open market under the previously announced share repurchase program and no shares of common stock were surrendered by its employees to pay their share of payroll taxes arising from vesting of restricted stock.

Item 6. Selected Financial Data

The selected consolidated financial data, set forth below should be read in conjunction with Item 7 and Item 8.

	June 30,				
	2020	2019	2018	2017	2016
Income Statement Data					
Revenues	$ 29,599,296	$ 43,229,621	$ 40,773,527	$ 34,253,681	$ 26,349,502
Cost of revenues	13,505,502	14,266,784	11,685,817	10,604,594	9,133,111
Depreciation, depletion and amortization	5,761,498	6,253,083	6,102,288	5,779,069	5,214,174
General and administrative expenses	5,259,659	5,072,931	6,773,781	4,985,408	9,079,597
Net loss on derivative contracts	1,383,204	—	—	—	—
Restructuring charges	—	—	—	4,488	1,257,433
Income from operations	3,689,433	17,636,823	16,211,641	12,880,122	1,665,187
Other income (expense)	66,643	1,222,604	(25,126)	4,855	32,565,954
Income tax provision (benefit)	(2,180,996)	3,482,361	(3,431,969)	4,840,664	9,570,779
Net income attributable to the Company	5,937,072	15,377,066	19,618,484	8,044,313	24,660,362
Dividends on preferred stock	—	—	—	250,990	674,302
Deemed dividend on preferred shares called for redemption	—	—	—	1,002,440	—
Net income attributable to common shareholders	$ 5,937,072	$ 15,377,066	$ 19,618,484	$ 6,790,883	$ 23,986,060
Earnings per common share:					
Basic	$ 0.18	$ 0.46	$ 0.59	$ 0.21	$ 0.73
Diluted	$ 0.18	$ 0.46	$ 0.59	$ 0.21	$ 0.73

	June 30, 2020	June 30, 2019	June 30, 2018	June 30, 2017	June 30, 2016
Balance Sheet Data					
Total current assets	$ 25,316,698	$ 35,178,927	$ 32,147,556	$ 26,142,527	$ 37,086,450
Total assets	92,138,236	95,761,844	93,662,544	88,268,668	97,451,051
Total current liabilities	4,278,859	2,752,694	4,430,214	2,718,894	8,528,908
Total liabilities	18,013,754	15,635,986	16,373,065	19,798,813	21,129,901
Total stockholders' equity	74,124,482	80,125,858	77,289,479	68,469,855	76,321,150
Number of common shares outstanding	32,956,469	33,183,730	33,080,543	33,087,308	32,907,863
Working capital	21,037,839	32,426,233	27,717,342	23,423,633	28,557,542
Cash dividends to common shareholders	10,740,754	13,272,058	11,594,541	8,432,435	6,565,823

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

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. In support of that objective, 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 enhancements, 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 our interests in the Hamilton Dome field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir, and overriding royalty interests in two onshore Texas wells.

Our interests in the Delhi field consist of a 23.9% working interest, with an associated 19.0% revenue interest and separate overriding royalty and mineral interests of 7.2% yielding a total net revenue interest of 26.2%. The field is operated by Denbury.

On November 1, 2019, the Company acquired mineral interests in the Hamilton Dome field consisting of a 23.5% working interest, with an associated 19.7% revenue interest (inclusive of a small overriding royalty interest). The field is operated by Merit, a private oil and gas company, who owns the vast majority of the remaining working interest in Hamilton Dome field. Our acquired interest in this field aligned with the Company's strategy of adding long-lived, low decline reserves expected to be supportive of our dividend over the long-term.

<u>Highlights for our Fiscal Year 2020 and Operations Update</u>

- Proved oil equivalent reserves at June 30, 2020 were 10.2 MMBOE, a 13% increase from the previous year primarily due to the acquisition of the Hamilton Dome field in November 2019. The Standardized Measure for proved reserves decreased 51% to $62 million, as the acquisition of the Hamilton Dome field was offset by the decrease in the average first day of the month net oil price from $64.54 per barrel of oil and $23.83 per barrel of natural gas liquids at June 30, 2019 to $46.37 per barrel of oil and $9.00 per barrel of natural gas liquids at June 30, 2020. Our proved reserves consist of 80% crude oil and 20% natural gas liquids, 82% are classified as proved developed producing and 18% are proved undeveloped.
- We recognized net income of $5.9 million, or $0.18 per diluted common share, our ninth consecutive year of reporting net income.
- Returned to shareholders $10.7 million in cash dividends and invested $2.5 million in stock repurchases in fiscal 2020. The Company has paid out to shareholders more than $70 million in cash dividends since inception of the dividend program in December 2013.
- Closed the acquisition of non-operated working interest in Hamilton Dome field on November 1, 2019 which included total proved reserves of 1.47 MMBOE as of June 30, 2020 as estimated by D&M, an independent reservoir engineering firm.
- Reported $12.4 million of cash flows from operations for the fiscal year ended June 30, 2020. We funded all operations, including $11.8 million of capital spending inclusive of our $9.3 million acquisition of our interest in the Hamilton Dome Field, from internal resources and remain debt free at June 30, 2020.

- In order to mitigate the impact of the growing global COVID-19 pandemic on our employees, we continue to follow local stay-at-home orders and remotely work from home with minimal disruptions to our business operations.
- We entered into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020 at a fixed swap price of $32.00 per barrel, recording a loss of $1.4 million at June 30, 2020. Of this amount, $1.9 million were non-cash, unrealized mark-to-market losses as commodity prices improved from those existing at fiscal year-end, offset in part by $0.5 million in realized gains during the fiscal fourth quarter.
- We completed remaining capital expenditures for the six-well water curtain program and related infrastructure preceding the planned Delhi Phase V development, which was delayed by the operator until the fourth quarter of 2021.
- In July 2020, Denbury Resources announced that it had entered into a restructuring support agreement with certain of its debt holders and filed a pre-packaged voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in Texas. Denbury Resources is seeking to eliminate $2.1 billion of debt. Denbury subsequently announced on September 3, 2020 that its plan to eliminate $2.1 billion of its bond debt has been confirmed by the court which will substantially reduce its debt and strengthen its balance sheet.

Oil & Natural Gas Liquids Reserves (based on SEC average NYMEX WTI oil price of $47.37 per barrel at June 30, 2020)

- **Proved oil equivalent reserves at June 30, 2020 were 10.2 MMBOE**, a 13% increase from the previous year primarily due to the acquisition of the Hamilton Dome field in November 2019. The Standardized Measure for proved reserves decreased 51% to $62 million, reflecting the decrease in the average first day of the month net oil price from $64.54 per barrel of oil and $23.83 per barrel of natural gas liquids at June 30, 2019 to $47.37 per barrel of oil and $9.00 per barrel of natural gas liquids at June 30, 2020. Price decreases are partially offset by the acquisition of the Hamilton Dome field in November 2019. Our proved reserves are 80% crude oil and 20% natural gas liquids, and of these proved reserves, 82% are classified as proved developed and producing and 18% are proved undeveloped.

The following table is a summary of our proved reserves as of June 30, 2020 and 2019:

	Proved		
	2020	2019	Change
Reserves MMBOE	10.2	9.0	13.3 %
% Developed	82%	82%	— %
Liquids %	100%	100%	— %
Standardized Measure ($MM)	$ 62	$ 127	(51)%

Additional property and project information is included under Item 1 and in Note 6 and Note 21 to our consolidated financial statements in Item 8, and in Exhibit 99.1 of this Form 10-K.

Delhi Field

Proved reserves volumes totaled 8.7 MMBOE compared to the prior year's 9.0 MMBOE. Year over year, decreased oil prices and temporary curtailment of CO_2 purchases since February 2020 has led to a 0.2 MMBOE, or a 2% negative revision in proved oil reserves. Adjustment of projecting NGL reserves independent of oil production resulted in a 0.6 MMBOE, or 46% positive revision to NGL reserves.

Gross production at Delhi in the fourth quarter of fiscal 2020 was 6,082 BOEPD, an 8% decrease compared to 6,597 BOEPD in the third fiscal quarter. Oil production was 4,985 BOPD, an 9% decrease from the third fiscal quarter’s 5,499 BOPD. NGL fourth quarter production of 1,097 BOEPD was virtually flat compared to prior quarter production. Oil production was significantly impacted by materially lower CO_2 purchases when the CO_2 purchase pipeline, upstream of Delhi field, was shut-in for repairs in late February throughout the end of fiscal 2020. The operator has commenced repairs to the pipeline and expects an in service date of October 2020. The loss of CO_2 purchases, coupled with the decline in oil prices, led to the operator electing to freeze non-essential capital projects through the end of fiscal 2020.

The average oil price realized by Evolution during the fourth quarter of fiscal 2020 was $23.74 compared to $47.27 during the previous quarter, a decrease of 50%. The average NGL price realized by Evolution during the fourth quarter of fiscal 2020 was $2.11 per barrel compared to $9.56 during the previous quarter, a decrease of 78%. The decline was attributable to the decrease in all realized commodity prices in fiscal fourth quarter. The COVID-19 pandemic, combined with a market share competition between certain members of the OPEC+ member nations, continued to adversely impact demand for commodity products, which caused a global supply/demand imbalance for oil that resulted in extreme volatility in benchmark oil prices, with prices ranging from a low of a negative price of $37.63 per Bbl to a high of $40.46 per Bbl during our fiscal fourth quarter.

Although we historically 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, in the fiscal fourth quarter, the field realized a discount to WTI of $4.26. Oil produced from Delhi field 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 that is reflected as a reduction in lease operating expense.

Our overall lifting costs for the year were $16.50 per BOE, which decreased 14.6% from $19.31 per BOE in the prior year. Gross CO_2 purchase volume rates for the fiscal 2020 averaged 51.9 MMcf per day, compared to 85.2 MMcf per day in the prior year, a 39% decrease due to the Delhi CO_2 purchase pipeline shut-in for repairs. This decrease together with a 14% lower price per mcf resulted in a 48% decrease in CO_2 cost compared to the prior year. Our cost of purchased CO_2, the largest single component of operating costs at Delhi, is directly tied to the price of oil sold from the Delhi field. Other lease operating expenses for fiscal 2020 decreased 5.6% compared to the prior year, primarily due to lower fuel gas, parts and workover expenses.

For fiscal 2020, our gross NGL production was 1,106 BOEPD, which sold at an average price of $9.59 per barrel, compared to prior year gross production of 1,171 BOEPD for which we realized $21.87 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. Our current mix of products is very rich containing higher value NGLs, such as pentanes and butane. 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 in the future.

The NGL plant includes an electric turbine that converts methane and part of the ethane processed by the plant into electricity. This turbine generates power primarily 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, smaller chain hydrocarbons (i.e. methane and ethane), thereby increasing the purity of the CO_2 recycle stream and improving the efficiency of the CO_2 flood throughout the field. Over time, the NGL plant is expected to increase and enhance the recovery of crude oil in the field. The NGL plant is not only providing feedstock to power the electric turbine, it is also producing significant quantities of higher value NGLs to sell to market.

Remaining estimated capital expenditures for our proved undeveloped reserves amount to approximately $6.38 per BOE for Phase V. Looking forward, the timing of plans for continued development of the eastern part of the Delhi field are dependent on the operator’s schedule 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.

Hamilton Dome

At June 30, 2020, we had total proved reserves of 1.5 MMBOE which was entirely comprised of oil as estimated by our independent petroleum engineering firm D&M.

Gross oil production at Hamilton Dome in the fourth quarter of fiscal 2020 was 1,642 BOPD, a 29% decrease compared to 2,328 BOPD in the third fiscal quarter quarter primarily due to the operator shutting in uneconomic wells at the extremely low oil price. There were limited capital expenditures in the field during fiscal 2020 due primarily to the decrease in oil prices. Most projects focused on maintenance, but in March 2020, a larger, and more efficient, ESP was installed in the Step Scale 117 which resulted in an increase in average production since completion of 5 BOPD. The average oil price realized by Evolution during the fourth quarter was $16.12 compared to $30.23 during the previous quarter, a decrease of 47%. Production from this field is transported by pipeline to customers in the Western Canadian Select market; prices are discounted from WTI. In the fourth quarter our realized price reflected a $11.88 per barrel discount from the WTI price. For this fiscal year, subsequent to our acquisition, our lifting costs at Hamilton Dome have averaged $28.93 per barrel.

Impact of Geopolitical Factors and the COVID-19 Pandemic

On March 11, 2020, the World Health Organization declared COVID-19 a pandemic, and on March 13, 2020, the United States of America declared a national emergency with respect to COVID-19. The virus has continued to spread in the United States of America and abroad. National, state, and local authorities have recommended social distancing, imposed quarantine and isolation measures, as well as mandatory business closures on large portions of the population. These measures, while intended to protect human life, are expected to have serious adverse impacts on domestic and foreign economies of uncertain severity and duration. The effectiveness of economic stabilization efforts, including government payments to affected citizens and industries, is uncertain.

The nature of the COVID-19 pandemic makes it extremely difficult to predict the impact on the Company's business and operations. However, the likely overall economic impact of the pandemic is viewed as highly negative to the general economy, especially the oil and natural gas industry. During the six months ended June 30, 2020, primarily driven by the COVID-19 pandemic and actions taken by OPEC+, the benchmark price of WTI dropped significantly. Although global outputs can be adjusted to support commodity pricing levels, the Company expects the price of crude oil to remain volatile in the near term. Uncertainty regarding the future actions of foreign oil producers, such as Saudi Arabia and Russia, and the risk that they take actions that will prolong or exacerbate the current over-supply of crude oil is also contributing to the recent decline in oil prices.

Currently, all of the Company's property interests are not operated by the Company and involve other third-party working interest owners. As a result, the Company has limited ability to influence or control the operation or future development of such properties. In light of the current price and economic environment, the Company continues to be proactive with its third-party operators to review spending and alter plans as appropriate.

The Company is focused on maintaining its operations and system of controls remotely and has implemented its business continuity plans in order to allow its employees to securely work from home. The Company was able to transition the operation of its business with minimal disruption and to maintain its system of internal controls and procedures.

Liquidity and Capital Resources

At June 30, 2020, we had $19.7 million in cash and cash equivalents, primarily impacted by the $9.3 million purchase of certain mineral interests in Hamilton Dome field in November 2019, compared to $31.6 million of cash and cash equivalents at June 30, 2019.

In addition, the Company has a senior secured reserve-based credit facility (the "Facility") with a maximum capacity of $50 million subject to a borrowing base determined by the lender based on the value of our oil and gas properties. The Facility had a $27 million borrowing base on June 30, 2020. However, our ability to access the borrowing base is also limited by our compliance with certain financial covenants, including a debt service ratio covenant, described below. As a consequence of declining oil prices adversely impacting our EBITDA upon which the debt service ratio is calculated, at June 30, 2020 our borrowings would have been limited to approximately $8 million. There are no borrowings outstanding under the Facility, which matures on April 11, 2021. The Facility is secured by substantially all of the reserves associated with the Delhi field.

Any future borrowings bear interest, at the Company's option, at either the London Interbank Offered Rate ("LIBOR") plus 2.75% or the Prime Rate, as defined under the Facility, plus 1.0%. The Facility contains covenants requiring 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, 2020, the Company was in compliance with all covenants contained in the Facility.

The Company has historically funded operations through cash from operations and working capital. The primary source of cash is the sale of produced oil and natural gas liquids. A portion of these cash flows is used to fund capital expenditures. The Company expects to manage future development activities in the Delhi field and the limited capital maintenance requirements of the Hamilton Dome field within the boundaries of its operating cash flow and existing working capital.

The Company is pursuing new growth opportunities through acquisitions and other transactions. In addition to cash on hand, the Company has limited access to an undrawn borrowing base available under its senior secured credit facility, The Company also has an effective shelf registration statement with the SEC under which the Company may issue up to $500 million of new debt or equity securities.

During the fiscal year ended June 30, 2020, the Company funded operations, capital expenditures and cash dividends with cash generated from operations resulting in a decrease of $11.9 million in cash. Uses of cash included the acquisition of the Hamilton Dome field ($9.3 million), cash dividends on common shares ($10.7 million) and repurchasing shares under the buyback program ($2.5 million). As of June 30, 2020, working capital was $21.0 million, a decrease of $9.3 million over working capital of $32.4 million at June 30, 2019.

The Board of Directors instituted a cash dividend payable on shares of our common stock in December 2013. The Company has since paid 27 consecutive quarterly dividends. Distribution of a substantial portion of cash flow in excess of operating and capital requirements through cash dividends is a priority of the Company’s financial strategy. However, due to current depressed price environment and a desire to preserve cash to potentially pursue opportunities that will grow dividends over time, the Board of Directors believed it was in the best interest of the Company to reduce its quarterly dividend rate from $0.10 per share to $0.025 per share, effective in the quarter ending June 30, 2020. The reduced dividend rate will continue to reward shareholders with a yield of approximately 3% at current stock price levels. The Company intends to grow dividend levels as appropriate.

In May 2015, the Board of Directors approved a share repurchase program covering up to $5 million of the Company’s common stock. The Company monitors its stock price and looks to opportunistically purchase its common stock when market conditions are deemed to be appropriate. During the year ended June 30, 2020, the Company purchased 440,666 shares at an average cost of $5.51 per share bringing its total to $4.0 million to purchase 706,858 common shares at an average price of $5.72 per share.

In early March 2020, oil prices declined rapidly. As a consequence of unprecedented commodity price volatility and uncertainty on April 6, 2020, the Company elected to enter into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020, at a fixed swap price of $32.00 per barrel. The fixed price swap contracts will significantly reduce volatility in the Company's near-term realized oil price and resulting revenues, thus supporting its current business plans and objectives. The Company expects to have sufficient liquidity to meet all its identified cash requirements for at least the next 12 months.

Capital Expenditures

For the year ended June 30, 2020, we incurred $11.8 million on capital projects consisting of $9.3 million for the acquisition of Hamilton Dome field, $0.9 million for a non-cash asset addition related to Hamilton Dome asset retirement obligations, $1.5 million at the Delhi field (primarily for the NGL plant and completion of the water curtain) and $0.1 million for capital workovers at Hamilton Dome.

Based on discussions with the Delhi and Hamilton Dome operators, we expect to continue to perform conformance workover projects and will likely incur additional maintenance capital expenditures, primarily at the Delhi field. Such amounts are not known or approved but we expect such expenditures to be in the range of $0.75 million to $1.0 million over the next 12 months. In addition, we have planned for Delhi Phase V development expenditures of approximately $1.9 million to be incurred in the fourth quarter of our fiscal 2021. Phase V development expenditures are expected to total $8.6 million with $3.7 million to be incurred in fiscal 2022 and the remainder over the next two years.

Our proved undeveloped reserves at June 30, 2020 included 1.86 MMBOE 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 the Company. Based on our discussions with the operator, we expect drilling to commence in fiscal 2022, but 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 over the next 24 months is expected to be met from cash flows from operations and current working capital.

Full Cost Pool Ceiling Test

At the year ended June 30, 2020, our capitalized costs of oil and gas properties were below the full cost valuation ceiling; however, we could experience an impairment if current price levels persist or worsen. The trend of lower oil prices reduced the excess, or cushion, of our valuation ceiling over our capitalized costs in the current quarter and may adversely impact our ceiling tests in future quarters. We cannot give assurance that a write-down of capitalized oil and gas properties will not be required in the future. Under the full cost method of accounting, capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the valuation “ceiling”). If capitalized costs exceed the full cost ceiling, the excess would be charged to expense as a write-down of oil and gas properties in the quarter in which the excess occurred. The quarterly ceiling test calculation requires that we use the average first day of the month price for our petroleum products during the 12-month period ending with the balance sheet date. The prices used in calculating our ceiling test at June 30, 2020 were $47.37 per barrel of oil and $9.00 per barrel of natural gas liquids. A significant decline from these prices would likely result in a ceiling test impairment charge.

Overview of Cash Flow Activities

The table below compares a summary of our consolidated statements of cash flows for year ended June 30, 2020 and 2019.

	June 30,		
Increases (Decreases) in Cash:	**2020**	**2019**	**Difference**
		(In Millions)	
Net cash provided by operating activities	$ 12.4	$ 24.1	$ (11.7)
Net cash used in investing activities	(11.1)	(6.8)	(4.3)
Net cash used in financing activities	(13.2)	(13.4)	0.2
Change in cash, cash equivalents and restricted cash	$ (11.9)	$ 3.9	$ (15.8)

Cash provided by operating activities in the current year decreased $11.7 million compared to fiscal 2019. The difference is primarily as the result of decrease in net income of $9.4 million due to lower realized commodity prices together with a $3.2 million increase in cash used by operating assets and liabilities. Enhanced Oil Recovery credits claimed on income tax returns for fiscal 2019, 2018 and 2017 resulted in an income tax refund receivable that contributed to the use of cash by operating activities.

Cash used in investing activities decreased $4.3 million primarily due to the acquisition of the Hamilton Dome field in November 2019. The decrease is partially offset by a reduction in capital expenditures in fiscal 2020 due to the decrease in realized commodity prices.

Cash used in financing activities remained relatively flat year over year as the reduction in cash used for cash dividends was offset by the Company's common share repurchase program in fiscal 2020. The Company reduced its quarterly dividend rate from $0.10 per share to $0.025 per share for the fourth quarter of fiscal year 2020. The Company spent a total of $2.5 million to purchase 440,666 shares of its common stock at an average price of $5.51.

Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2020, 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					
AFE purchase commitments in connection with joint interest agreements	$ 201,104	$ 201,104	$ —	$ —	$ —
Operating lease	139,268	54,290	84,978	—	—
Other Obligations					
Asset retirement obligations	2,588,894	—	65,163	43,442	2,480,289
Total Obligations	$ 2,929,266	$ 255,394	$ 150,141	$ 43,442	$ 2,480,289

Results of Operations
Years Ended June 30, 2020 and 2019

Revenues

Compared to the prior fiscal year, fiscal 2020 revenues decreased 31.5% due to 32.1% lower realized commodity prices. The decrease is partially offset by a very slight increase in production volumes. The following table summarizes total production volumes, daily production volumes, average realized prices and revenues:

	Years Ended June 30,			
	2020	2019	Variance	Variance %
Oil and gas production				
Crude oil revenues	$ 28,578,879	$ 40,779,052	$ (12,200,173)	(29.9)%
NGL revenues	1,018,349	2,449,359	(1,431,010)	(58.4)%
Natural gas revenues	2,068	1,210	858	70.9 %
Total revenues	$ 29,599,296	$ 43,229,621	$ (13,630,325)	(31.5)%
Crude oil volumes (Bbl)	638,464	626,879	11,585	1.8 %
NGL volumes (Bbl)	106,159	112,013	(5,854)	(5.2)%
Natural gas volumes (Mcf)	1,087	459	628	136.8 %
Equivalent volumes (BOE)	744,804	738,968	5,836	0.8 %
Crude oil (BOPD, net)	1,744	1,717	27	1.6 %
NGLs (BOEPD, net)	290	307	(17)	(5.5)%
Natural gas (BOEPD, net)	—	1	(1)	n.m
Equivalent volumes (BOEPD, net)	2,034	2,025	9	0.4 %
Crude oil price per Bbl	$ 44.76	$ 65.05	$ (20.29)	(31.2)%
NGL price per Bbl	9.59	21.87	(12.28)	(56.1)%
Natural gas price per Mcf	1.90	2.64	(0.74)	(28.0)%
Equivalent price per BOE	$ 39.74	$ 58.50	$ (18.76)	(32.1)%

n. m. Not meaningful.

(Gain) Loss on Derivative Contracts

Periodically, we utilize commodity derivative financial instruments to reduce our exposure to fluctuations in crude oil prices. This amount represents the (i) (gain) loss related to fair value adjustments on our open, or unrealized, derivative contracts and (ii) (gains) losses on settlements of derivative contracts for positions that have settled or been realized.

	Years Ended June 30,			
	2020	2019	Variance	Variance %
Oil Derivative Contracts				
Realized (gain) loss on derivatives, net	$ (528,139)	$ —	$ (528,139)	n.m.
Unrealized (gain) loss on derivatives	1,911,343	—	1,911,343	n.m.
Loss on derivatives	$ 1,383,204	$ —	$ 1,383,204	n.m.
Crude oil price per Bbl (including impact of realized derivatives)	$ 45.59			

n. m. Not meaningful.

Production Costs

Production costs (also referred to as lease operating expenses) are presented in two components: (i) CO_2 costs for the Delhi field and (ii) other production costs for both the Delhi and Hamilton Dome fields. The $0.8 million decrease in total production costs was due to a 47.5% decrease in CO_2 costs. The decrease is partially offset by a 31.8% increase in other production costs.

	Years Ended June 30,			
	2020	2019	Variance	Variance %
CO_2 costs (a)	$ 3,501,507	$ 6,674,905	$ (3,173,398)	(47.5)%
Other production costs	10,003,995	7,591,879	2,412,116	31.8 %
Total production costs	$ 13,505,502	$ 14,266,784	$ (761,282)	(5.3)%
CO_2 costs per BOE	$ 4.70	$ 9.03	$ (4.33)	(48.0)%
All other production costs per BOE	13.43	10.28	3.15	30.6 %
Production costs per BOE	$ 18.13	$ 19.31	$ (1.18)	(6.1)%

(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 and transportation costs as per contract terms.

	Years Ended June 30,			
	2020	2019	Variance	Variance %
CO_2 costs per mcf	$ 0.77	$ 0.90	$ (0.13)	(14.4)%
CO_2 volumes (MMcf per day, gross)	51.9	85.2	(33.3)	(39.1)%

The $3.2 million decrease in CO_2 costs was due to a 39.1% decrease in rate of purchased volumes together with a 14.4% decrease in price per Mcf associated with the lower realized oil price. The upstream pipeline that supplies CO_2 to the Delhi field was shut-in on February 22, 2020, when a pressure loss was detected. CO_2 purchases were temporarily suspended through our fiscal year-end. CO_2 purchases provide approximately 20% of the injected volumes in the field and the field’s recycle facilities provide the other 80%. The recycle facilities continued to operate as usual during the purchase pipeline suspension. The pipeline is owned and operated by Denbury Resources, and the Company does not have any ownership in the portion of the pipeline under repair. The operator expects the pipeline to be back in service in October 2020.

Compared to fiscal 2019, "Other production costs" increased 31.8% primarily due to the acquisition of the Hamilton Dome field in November 2019. The Delhi field's "Other production costs" decreased slightly by 5.6% impacted by cost control measures as a result of lower oil prices.

Compared to fiscal 2019, Delhi field costs decreased 15% to $16.50 per BOE of Delhi current year production primarily due to lower CO_2 costs, as discussed above.

For fiscal 2020, Hamilton Dome field costs per BOE were $28.93.

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

Total DD&A expense was 7.9% lower compared to the same one year-ago period due to an 8.7% decrease in the oil and gas DD&A amortization rate; the volume change between the two periods was very slight. The integration of the Hamilton Dome asset contributed to an overall lower composite DD&A per BOE rate.

	Years Ended June 30,			
	2020	2019	Variance	Variance %
DD&A of proved oil and gas properties	$ 5,592,651	$ 6,122,515	$ (529,864)	(8.7)%
Depreciation of other property and equipment	8,779	15,498	(6,719)	(43.4)%
Amortization of intangibles	13,564	13,564	—	— %
Accretion of asset retirement obligations	146,504	101,506	44,998	44.3 %
Total DD&A	$ 5,761,498	$ 6,253,083	$ (491,585)	(7.9)%
Oil and gas DD&A per BOE	$ 7.51	$ 8.29	$ (0.78)	(9.4)%

General and Administrative Expenses

Total general and administrative expenses for fiscal 2020 increased $0.2 million, or 3.7%, to $5.3 million from the same year-ago period. The increase is primarily due to higher non-cash stock-based compensation of $0.4 million related to new grants associated with the hiring of a new executive officer and increased consulting expense of $0.1 million, partially offset by a decrease of $0.3 million in bonus expense.

Other Income and Expenses

Other income and expenses (net) decreased due primarily to the non-recurring Enduro transaction breakup fee income received during fiscal 2019. During May 2018, the Company entered into a Purchase and Sale Agreement 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. 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. Interest income is lower due to lower invested balances together with declining interest rates.

	Years Ended June 30,			
	2020	2019	Variance	Variance %
Enduro transaction breakup fee	—	1,100,000	(1,100,000)	(100.0)%
Interest and other income	177,418	239,150	(61,732)	(25.8)%
Interest expense	(110,775)	(116,546)	5,771	(5.0)%
Total other income, net	$ 66,643	$ 1,222,604	$ (1,155,961)	(94.5)%

Net Income

Net income available to common stockholders for the year ended June 30, 2020 decreased $9.4 million, or 61%, to $5.9 million compared to the last fiscal year. Pre-tax income decreased due to the aforementioned revenue and expense variances. Our income tax provision decreased primarily due to lower pre-tax income as our effective income tax rate was relatively unchanged from the year-ago period. During the current period, we recorded a $2.8 million income tax benefit related to Enhanced Oil Recovery credits claimed on income tax returns for fiscal 2019, 2018 and 2017 .

	Years Ended June 30,			
	2020	2019	Variance	Variance %
Income before income taxes	3,756,076	18,859,427	(15,103,351)	(80.1)%
Income tax provision (benefit)	(2,180,996)	3,482,361	(5,663,357)	(162.6)%
Net income available to common stockholders	$ 5,937,072	$ 15,377,066	$ (9,439,994)	(61.4)%
Income tax provision (benefit) as a percentage of income before income taxes	(58)%	18%		

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, liabilities, and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. These policies, together with our estimates, have a significant effect on our consolidated financial statements. Our significant accounting policies are included in Note 2 to our consolidated statements in Item 8. 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 and 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. 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, 2020, we had no unevaluated property costs. Oil and natural gas property costs included represent non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling 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 for determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex and requires 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; this includes 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 prepared by our third party independent engineers represent the most accurate assessments possible, 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. These changes could affect 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, 2020 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, 2020 of 5%, 10% and 15% would affect depreciation, depletion, and amortization expense by approximately $290,000, $612,000, and $970,000, 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; this would result in an increase to our income tax expense. As of June 30, 2020, 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, we believe that it is more likely than not that the Company will realize the benefits of its net deferred tax assets at the time of this report. 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. Refer to Note 2 to our consolidated financial statements in Item 8. Consolidated Financial Statements and Supplementary Data 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, 2020.

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.

Derivative Instruments and Hedging Activity

We are exposed to various risks, including energy commodity price risk, such as price differentials between the NYMEX commodity price and the index price at the location where our production is sold. When oil, natural gas, and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we monitor commodity prices to identify the potential need for the use of derivative financial instruments to provide partial protection against declines in oil prices.We do not enter into derivative contracts for speculative trading purposes. In early March 2020, oil prices declined rapidly. As a consequence of unprecedented commodity price volatility and uncertainty on April 6, 2020, we elected to enter into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020, at a fixed swap price of $32.00 per barrel. The fixed price swap contracts will significantly reduce volatility in our near-term realized oil price and resulting revenues, thus supporting our current business plans and objectives.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competitive market makers. As of June 30, 2020, we did not post collateral under our derivative contract as it is an uncollateralized trade. We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, ("ASC 815"). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 20 to our consolidated financial statements for more details.

Item 8. Consolidated Financial Statements and Supplementary Data

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, 2020 and 2019, 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, 2020 and 2019, 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.

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 Public Company Accounting Oversight Board (United States) (“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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

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 10, 2020

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

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2020	June 30, 2019
Assets		
Current assets		
Cash and cash equivalents	$ 19,662,528	$ 31,552,533
Receivables from oil and gas sales	1,919,213	$ 3,168,116
Receivables for federal and state income tax refunds	3,243,271	—
Prepaid expenses and other current assets	491,686	458,278
Total current assets	25,316,698	35,178,927
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	66,512,281	60,346,466
Other property and equipment, net	17,639	26,418
Total property and equipment, net	66,529,920	60,372,884
Other assets, net	291,618	210,033
Total assets	$ 92,138,236	$ 95,761,844
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 1,471,679	$ 2,084,140
Accrued liabilities and other	716,648	537,755
Derivative contract liabilities	1,911,343	—
State and federal taxes payable	179,189	130,799
Total current liabilities	4,278,859	2,752,694
Long term liabilities		
Deferred income taxes	11,061,023	11,322,691
Asset retirement obligations	2,588,894	1,560,601
Operating lease liability	84,978	—
Total liabilities	18,013,754	15,635,986
Commitments and contingencies (Note 16)		
Stockholders' equity		
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 32,956,469 and 33,183,730 shares as of June 30, 2020 and 2019, respectively	32,956	33,183
Additional paid-in capital	41,291,446	42,488,913
Retained earnings	32,800,080	37,603,762
Total stockholders' equity	74,124,482	80,125,858
Total liabilities and stockholders' equity	$ 92,138,236	$ 95,761,844

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Years Ended June 30, 2020	Years Ended June 30, 2019
Revenues		
Crude oil	$ 28,578,879	$ 40,779,052
Natural gas liquids	1,018,349	2,449,359
Natural gas	2,068	1,210
Total revenues	29,599,296	43,229,621
Operating costs		
Production costs	13,505,502	14,266,784
Depreciation, depletion, and amortization	5,761,498	6,253,083
Net loss on derivative contracts	1,383,204	—
General and administrative expenses*	5,259,659	5,072,931
Total operating costs	25,909,863	25,592,798
Income from operations	3,689,433	17,636,823
Other		
Enduro transaction breakup fee	—	1,100,000
Interest and other income	177,418	239,150
Interest (expense)	(110,775)	(116,546)
Income before income tax provision	3,756,076	18,859,427
Income tax provision (benefit)	(2,180,996)	3,482,361
Net income (loss) attributable to common shareholders	$ 5,937,072	$ 15,377,066
Earnings per common share		
Basic	$ 0.18	$ 0.46
Diluted	$ 0.18	$ 0.46
Weighted average number of common shares outstanding		
Basic	33,031,149	33,160,283
Diluted	33,033,091	33,169,718

* General and administrative expenses for the years ended June 30, 2020 and 2019 included non-cash stock-based compensation expense of $1,285,663 and $888,162, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended June 30,	
	2020	**2019**
Cash flows from operating activities		
Net income attributable to the Company	$ 5,937,072	$ 15,377,066
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	5,761,498	6,253,083
Stock-based compensation	1,285,663	888,162
Settlement of asset retirement obligations	(76,832)	—
Deferred income taxes	(261,668)	767,256
Net loss on derivative contracts	1,383,204	—
Payments received for derivative settlements	793,327	—
Other	39,783	15,156
Changes in operating assets and liabilities:		
Receivables	(1,994,368)	773,800
Prepaid expenses and other current assets	(33,408)	66,229
Accounts payable and accrued expenses	(486,010)	(90,891)
Income taxes payable	48,390	8,039
Net cash provided by operating activities	12,396,651	24,057,900
Cash flows from investing activities		
Acquisition of oil and gas properties	(9,337,716)	—
Development of oil and natural gas properties	(1,724,829)	(6,746,142)
Capital expenditures for other property and equipment	—	(11,509)
Net cash used by investing activities	(11,062,545)	(6,757,651)
Cash flows from financing activities		
Common share repurchases, including shares surrendered for tax withholding	(2,483,357)	(156,791)
Common stock dividends paid	(10,740,754)	(13,272,058)
Net cash provided by (used in) financing activities	(13,224,111)	(13,428,849)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(11,890,005)	3,871,400
Cash, cash equivalents, and restricted cash, beginning of year	31,552,533	27,681,133
Cash, cash equivalents, and restricted cash, end of year *	$ 19,662,528	$ 31,552,533

* Neither annual period had any restricted cash balances.

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, 2020 and 2019

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value				
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)	—	—	—
Forfeitures of restricted stock	—	—	—	—	—	—
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
Issuance of restricted common stock	271,778	272	(272)	—	—	—
Forfeitures of restricted stock	(49,118)	(49)	49	—	—	—
Common share repurchases, including shares surrendered for tax withholding	—	—	—	—	(2,483,357)	(2,483,357)
Retirements of treasury stock	(449,921)	(450)	(2,482,907)	—	2,483,357	—
Stock-based compensation	—	—	1,285,663	—	—	1,285,663
Net income attributable to the Company	—	—	—	5,937,072	—	5,937,072
Common stock cash dividends	—	—	—	(10,740,754)	—	(10,740,754)
Balance, June 30, 2020	32,956,469	$ 32,956	$ 41,291,446	$ 32,800,080	$ —	$ 74,124,482

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Organization and Basis of Preparation

Nature of Operations. Evolution Petroleum Corporation 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 consist of our interests in the Delhi Holt-Bryant Unit in the Delhi field in Northeast Louisiana, a CO_2 enhanced oil recovery project, our interests in the Hamilton Dome field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir, and overriding royalty interests in two onshore Texas wells.

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.

Risk and Uncertainties. The Company is continuously monitoring the current and potential impacts of the COVID-19 pandemic on its business, including how it has and may continue to impact its financial results, liquidity, employees and the operations of the Delhi and Hamilton Dome fields in which we hold non-operated interests. During the six months ended June 30, 2020, primarily driven by the COVID-19 pandemic and actions taken by OPEC+, the benchmark price of WTI has declined to levels that have adversely impacted our earnings and reduced the maximum amount we could borrow under our senior secured facility.

In response to the pandemic, both of our operators have taken actions such as reducing operating and capital expenditures. At Hamilton Dome the operator has also temporarily shut-in some producing wells. In addition to the above, we also believe the pandemic has slowed the repair schedule of the Delhi CO_2 supply pipeline which together with the foregoing have negatively impacted our production. All of the Company’s property interests are not operated by the Company and 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. However, the Company has been proactive with its third-party operators to review spend and alter plans as appropriate.

The Company is focused on maintaining its operations and system of controls remotely and has implemented its business continuity plans in order to allow its employees to securely work from home. The Company was able to transition the operation of its business with minimal disruption and to maintain its system of internal controls and procedures.

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. At June 30, 2020 and 2019, we had no such balances.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable consist of accrued hydrocarbon revenues due under normal trade terms, generally requiring payment within 30 to 60 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. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2020 and 2019, 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; 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, 2020 and 2019.

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. It is associated with an 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, 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 geographic locations. 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 collectability 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 from oil and gas sales” in our consolidated balance sheets. As of June 30, 2020 and 2019 receivables from contracts with customers were $1.9 million and $3.2 million, respectively.

Derivative Instruments. The Company follows ASC 815, Derivatives and Hedging ("ASC 815"). From time to time, in accordance with the Company’s policy, it may hedge a portion of its forecasted oil and natural gas liquids production. All derivative instruments are recorded on the consolidated balance sheet as either an asset or liability measured at fair value. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to an ISDA master agreement; the agreement provides for net settlement over the term of the contract and in the event of default or termination of the contract. Although the derivative instruments provide an economic hedge of the Company’s exposure to commodity price volatility, the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in “Net (gain) loss on derivative instruments” on the consolidated statements of operations.

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 and 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 that 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 which is based on the technical merits of the position. We 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); 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 - Leases

Effective July 1, 2019, the Company adopted the new standard using a modified retrospective approach and elected to use the optional transition methodology whereby reporting periods prior to adoption continue to be presented in accordance with legacy accounting guidance, Accounting Standard Codification 840 - Leases. Upon transition, we recognized a right of use ("ROU") asset (or operating lease right-of-use asset) and an operating lease liability with no retained earnings impact. We applied the following practical expedients as provided in the standards update which provide elections to not reassess:

- Not to apply the recognition requirements in the lease standard to short-term leases (a lease that at commencement date has a lease term of 12 months or less and does not contain a purchase option that the Company is reasonably certain to exercise).
- Whether an expired or existing pre-adoption date contracts contained leases.
- Lease classification of any expired or existing leases.
- Initial direct costs for any expired or existing leases.
- Not to separate lease components from non-lease components in a contract and accounting for the combination as a lease (reflected by asset class).

Adoption of the new standard did not impact our consolidated statements of operations, cash flows or stockholders’ equity. At adoption we recorded our operating lease as follows:

Asset (Liability)	Balance June 30, 2019	Adjustment at Adoption July 1, 2019
Operating lease right-of-use asset	$ —	$ 161,125
Accrued liabilities and other:		
Deferred rent	$ (4,338)	$ 4,338
Operating lease liability	$ —	$ (26,194)
Operating lease liabilities - long-term	$ —	$ (139,269)

Recently Issued Accounting Pronouncements

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. Early adoption is permitted and entities must adopt the amendment using a modified retrospective approach to the first reporting period in which the guidance is effective. For smaller reporting companies, as provided by Accounting Standards Update 2019-10, Financial Instruments - Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842), ASU 2016-13 is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2022. The adoption of ASU 2016-13 is currently not expected to have a material effect on our consolidated financial statements.

In December 2019, the FASB issued ASU No. 2019-12, Income Taxes ("Topic 740") - Simplifying the Accounting for Income Taxes. ASU 2019-12 is intended to simplify accounting for income taxes. It removes certain exceptions to the general principles in Topic 740 and amends existing guidance to improve consistent application. ASU 2019-12 is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2020. Early adoption is permitted. We are currently evaluating the impact of ASU 2019-12 on our consolidated financial statements.

Note 3 – Revenue Recognition

Our revenue is primarily generated from our interests in the Delhi field in Northeast Louisiana and, our interests in the Hamilton Dome field in Wyoming. Additionally, an overriding royalty interest retained in a past divestiture of Texas properties provided de minimis revenue:

	June 30,	
	2020	2019
Revenues		
Crude oil	$ 28,578,879	$ 40,779,052
Natural gas liquids	1,018,349	2,449,359
Natural gas	2,068	1,210
Total revenues	$ 29,599,296	$ 43,229,621

We are a non-operator and presently do not take production in kind and do not negotiate contracts with customers. We recognize crude oil, natural gas liquids, and natural gas production revenue at the point in time when custody and title (“control”) of the product transfers to the customer. Transfer of control drives the presentation of post-production expenses such as transportation, gathering, and processing deductions within the accompanying statements of operations. Fees and other deductions incurred prior to control transfer are recorded within the production costs line item on the accompanying consolidated statements of operations, while fees and other deductions incurred subsequent to control transfer are embedded in the price and effectively recorded as a reduction of crude oil, natural gas liquids, and natural gas production revenue.

Judgments made in applying the guidance in Accounting Standards Codification Topic 606, Revenue from Contracts with Customers, relate primarily to determining the point in time when control of product transfers to the customer. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company’s contractual performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied at a point in time upon control transferring to a customer at a specified delivery point. Consideration is allocated to satisfied performance obligations at the end of an accounting period.

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received one to two months after production has occurred, which is typical in the industry. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for the sale of the product. Estimated revenue due to the Company is recorded within the receivables line item on the accompanying consolidated balance sheets until payment is received. The accounts receivable balances from contracts with customers as of June 30, 2020 and 2019, as presented on our respective consolidated balance sheets, were $1.9 million and $3.2 million, respectively. To estimate accounts receivable from operators' contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser. Revenue recognized during the fiscal year ended June 30, 2020 and 2019 related to performance obligations satisfied in prior reporting periods, was immaterial.

Note 4 – Leases

Operating leases are reflected as an operating lease ROU asset included in "Other assets, net", and as a ROU liability in "Accrued liabilities and other" and "Operating lease liability" on our consolidated balance sheets. Operating lease ROU assets and liabilities are recognized at the commencement date of an arrangement based on the present value of lease payments over the lease term. In addition to the present value of lease payments, the operating lease ROU asset would also include any lease payments made to the lessor prior to lease commencement less any lease incentives and initial direct costs incurred, if any. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term. Certain leases have payment terms that vary based on the usage of the underlying assets. Variable lease payments are not included in ROU assets and lease liabilities. For all operating leases, lease and non-lease components are accounted for as a single lease component.

As a non-operator in recent years and having adequate liquidity, the Company has generally not entered into lease transactions. Presently, our only operating lease is for corporate office space in Houston, Texas, effective May 1, 2019 and which expires November 30, 2022. Presently we have one operating lease for office space, no finance leases and no short-term leases.

The Company makes certain assumptions and judgments when evaluating a contract that meets the definition of a lease under Topic 842. At adoption, July 1, 2019, as our lease did not provide an implicit rate, we used our prime-rate-based borrowing rate under our senior secured credit facility as our incremental borrowing as the term facility was based on a similar term and is appropriately risk-adjusted. We determined lease term by considering any option available to extend or to early terminate the lease which we believed was reasonably certain to be exercised.

At June 30, 2020, maturities of our operating lease liability are as follows:

Fiscal Year	Operating Lease Liability
2021	59,945
2022	61,843
2023	26,098
Total lease payments	147,886
Less imputed interest	(8,617)
Total lease liability	$ 139,269

Supplemental cash flow, balance sheet, and other disclosures information related to our operating leases are as follows:

	As of and For the Year Ended June 30, 2020
Cash Flow:	
Cash paid for amounts included in the measurement of lease liabilities	$ 4,903
ROU asset added in exchange for lease obligation at adoption	161,125
Balance Sheet:	
Operating lease ROU asset (included in other assets)	117,193
Accrued liabilities - current	54,290
Operating lease liability - long-term	84,978
Other:	
Weighted average remaining lease term in years	2.66
Weighted average discount rate	5.15%

Note 5 – Prepaid Expenses and Other Current Assets

	June 30, 2020	June 30, 2019
Prepaid insurance	$ 289,999	$ 206,198
Prepaid federal and state income taxes	86,208	121,679
Prepaid investor relations and other	115,479	130,401
Prepaid expenses and other current assets	$ 491,686	$ 458,278

Note 6 – Property and Equipment

	June 30, 2020	June 30, 2019
Oil and natural gas properties:		
Property costs subject to amortization	$ 107,390,379	$ 95,622,153
Less: Accumulated depreciation, depletion, and amortization	(40,878,098)	(35,275,687)
Unproved properties not subject to amortization	—	—
Oil and natural gas properties, net	66,512,281	60,346,466
Other property and equipment:		
Furniture, fixtures and office equipment, at cost	154,731	154,731
Less: Accumulated depreciation	(137,092)	(128,313)
Other property and equipment, net	$ 17,639	$ 26,418

As of June 30, 2020 and 2019, all oil and gas property costs were being amortized.

During the years ended June 30, 2020 and 2019, the Company incurred capital expenditures of $1.5 million and $5.2 million, respectively.

Hamilton Dome Acquisition

On November 1, 2019, and effective as of October 1, 2019, our wholly-owned subsidiary, Evolution Petroleum West, Inc., a Delaware corporation, purchased a 23.5% non-operated working interest and a 19.7% revenue interest in the Hamilton Dome unitized field located in Hot Springs County, Wyoming, from entities owned or controlled by Merit Energy Company ("Merit") of Dallas, Texas. At closing on November 1, 2019, we paid a cash purchase price of $9.5 million subject to customary purchase price adjustments, which were settled in December 2019 upon our receipt of a $0.2 million cash payment made by Merit. Given the effective date of the transaction, the purchase price adjustment consisted of our interest's share of sales proceeds from October sales net of our share of operating expenses. Commencing November 1, 2019, we began recording our share of Hamilton Dome revenues, related expenses, and capital costs. In connection with this acquisition, the Company recorded a $0.9 million non-cash addition of asset retirement obligations of wells and related assets.

The unit includes producing and water injection wells and associated facilities producing crude oil from proved developed reserves. There were no proved undeveloped reserves. We accounted for this acquisition transaction as an asset purchase.

Note 7 – Other Assets

	June 30, 2020	June 30, 2019
Royalty rights	108,512	108,512
Less: Accumulated amortization of royalty rights	(61,037)	(47,474)
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	(157,084)	(141,927)
Right of use asset under operating lease	161,125	—
Less: Accumulated amortization of right of use asset	(43,932)	—
Software license	20,662	20,662
Less: Accumulated amortization of software license	(14,350)	(7,462)
Other assets, net	$ 291,618	$ 210,033

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 with 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

	June 30, 2020	June 30, 2019
Accrued incentive and other compensation	$ 176,636	$ 369,719
Asset retirement obligations due within one year	—	50,244
Accrued franchise taxes	100,978	5,738
Accrued ad valorem taxes	108,000	100,500
Payable for settled derivatives	265,188	—
Operating lease liability, current	54,290	—
Accrued - other	11,556	11,554
Accrued liabilities and other	$ 716,648	$ 537,755

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, 2020 and 2019:

	Years Ended		
	2020		2019
Asset retirement obligations — beginning of period	$ 1,610,845		$ 1,422,955
Liabilities incurred	944,278	(a)	31,268
Liabilities settled	(86,592)	(b)	—
Accretion of discount	146,504		101,506
Revisions to previous estimates	(26,141)		55,116
Asset retirement obligations — end of period	2,588,894		1,610,845
Less: current asset retirement obligations	—		(50,244)
Long-term portion of asset retirement obligations	$ 2,588,894		$ 1,560,601

(a) Liabilities incurred in fiscal 2020 included $0.9 million from our acquisition of our Hamilton Dome interest and remainder related to facilities at the Delhi field.

(b) We abandoned one well in the Delhi field and four wells in the Hamilton Dome field.

Note 10 – Stockholders' Equity

Common Stock

As of June 30, 2020, we had 32,956,469 shares of common stock outstanding.

The Company began paying quarterly cash dividends on common stock in December 2013. As of June 30, 2020, we have cumulatively paid $70.2 million in cash dividends. We paid dividends of $10,740,754 and $13,272,058 from retained earnings to our common shareholders during the years ended June 30, 2020 and 2019, respectively. The following table reflects the dividends paid per common share in each quarter within the respective two fiscal years:

	Fiscal Year	
	2020	2019
Fourth quarter ended June 30,	$0.025	$0.100
Third quarter ended March 31,	$0.100	$0.100
Second quarter ended December 31,	$0.100	$0.100
First quarter ended September 30,	$0.100	$0.100

In May 2015, the Board of Directors approved a share repurchase program covering up to 5 million of the Company's common stock. Since inception of the program through June 30, 2020, the Company has spent $4.0 million to repurchase 706,858 common shares at an average price of $5.72 per share. Under the program's terms, shares are repurchased only on the open market and in accordance with the requirements of the SEC. Such shares are initially recorded as treasury stock, then subsequently canceled. The timing and amount of repurchases depends upon several factors, including financial resources and market and business conditions. There is no fixed termination date for this repurchase program, and it may be suspended or discontinued at any time.

The Company has also acquired treasury stock from holders of newly vested stock-based awards to fund the recipients' payroll tax withholding obligations. Such shares were valued at fair market value on the date of vesting.

The treasury shares were subsequently canceled. The following summarized the Company's treasury stock purchases in its last two fiscal years.

	Common Shares Acquired	Average Price per Share	Treasury Stock Purchases
Year Ended June 30, 2020:			
Shares surrendered for tax withholding upon vesting	9,255	$5.90	$ 54,565
Share repurchase program	440,666	$5.51	2,428,792
Total	449,921	$5.52	$ 2,483,357
Year Ended June 30, 2019:			
Shares surrendered for tax withholding upon vesting	17,994	$8.57	$ 154,179
Share repurchase program	430	$6.07	2,612
Total	18,424	$8.51	$ 156,791

Tax Treatment of Dividends to Recipients

Based on our current projections for the fiscal year ended June 30, 2020, we expect that 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, 2019, 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, non-statutory stock options, stock appreciation rights, restricted stock awards, 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, 2020, 390,489 shares remained available for grant under the 2016 Plan.

All remaining outstanding awards granted under the 2004 Plan have vested during the year ended June 30, 2020.

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 typically 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.

In July 2019, the new chief executive officer upon his employment received 48,872 shares of serviced-based restricted common stock which vest in three equal amounts on June 30, 2020, 2021 and 2022. He was also awarded a total of 200,000 market-based restricted stock units consisting of four equal tranches, each of which may vest only if its respective stock price requirement is met before the award term expires. Each tranche has a separate stated price requirement and respective vesting will occur only if, before July 1, 2023, the ninety-day trailing average Company stock share price equals or exceeds its tranche price requirement.

During the year ended June 30, 2020, we also granted 52,119 service-based and 104,236 market-based Restricted Stock awards to our employees as well as 56,395 service-based awards to the Company's directors.

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.

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, 2020, there were no performance-based awards outstanding.

Market-based awards vest if their respective two- or three-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 years ended June 30, 2020 and 2019 were:

	Year Ended June 30,	
	2020	2019
Weighted average fair value of market-based awards granted	$ 3.79	$ 8.24
Risk-free interest rate	1.65% to 1.87%	2.69%
Expected life in years	1.35 to 2.56	2.82
Expected volatility	38.6% to 43.7%	41.8%
Dividend yield	6% to 7.2%	4.0%

Unvested Restricted Stock awards at June 30, 2020 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Service-based awards	155,318	$ 5.88
Market-based awards	129,710	5.10
Unvested at June 30, 2020	285,028	$ 5.53

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2020:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2020	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2019	176,683	$ 8.09	$ —	
Service-based shares granted	157,386	5.73		
Market-based shares granted	104,236	4.34		
Vested	(104,159)	7.19		
Forfeited	(49,118)	9.35		
Unvested at June 30, 2020	285,028	$ 5.53	$ 1,001,477	1.74

The following is a summary of Restricted Stock that vested during the last two fiscal years:

	Year Ended June 30,	
	2020	2019
Vesting-date intrinsic value of Restricted Stock	$ 477,647	$ 1,141,631
Grant-date fair value of vested Restricted Stock	$ 748,893	$ 909,678
Number of awards that vested	104,159	133,776

The following table summarizes Contingent Restricted Stock activity for the year ended June 30, 2020:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2020	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2019	10,156	$ 3.42		
Market-based awards granted	200,000	3.50		
Vested	(10,156)	3.42		
Unvested at June 30, 2020	200,000	$ 3.50	$ 156,591	0.52

All of these outstanding awards at June 30, 2020 are market-based awards.

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

	Year Ended June 30,	
	2020	2019
Vest-date intrinsic value of Contingent Restricted Stock	$ 60,225	$ 105,227
Grant-date fair value of vested Contingent Restricted Stock	$ 34,734	$ 60,266
Number of awards that vested	10,156	10,629

Stock-based Compensation Expense

For the years ended June 30, 2020, and 2019, we recognized stock-based compensation expense related to Restricted Stock and Contingent Restricted Stock grants of $1,285,663 and $888,162, respectively.

Note 12 – Supplemental Disclosure of Cash Flow Information

	June 30,	
	2020	2019
Income taxes paid	$ 1,241,538	$ 2,762,919
Non-cash transactions:		
Decrease in accrued purchases of property and equipment	(212,456)	(1,603,290)
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	918,137	86,384

Note 13 – Income Taxes

We file a consolidated federal income tax return in the United States of America in addition to 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, 2020 and 2019. 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, 2016 through June 30, 2019 for federal tax purposes and for the years ended June 30, 2015 through June 30, 2019 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, 2020	June 30, 2019
Current:		
Federal	$ (2,264,850)	$ 2,343,512
State	345,522	371,593
Total current income tax provision (benefit)	(1,919,328)	2,715,105
Deferred:		
Federal	(266,482)	387,541
State	4,814	379,715
Total deferred income tax provision (benefit)	(261,668)	767,256
Total income tax provision (benefit)	$ (2,180,996)	$ 3,482,361

For the years ended June 30, 2020 and 2019, respectively, we recognized income tax benefit of $(2.2) million and an income tax expense of $3.5 million reflecting corresponding effective tax rates of (58.1)% and 18.5%, respectively. During the current year we undertook a project to seek potential cash tax savings opportunities identifying available Enhanced Oil Recovery credits ("EOR credits") related to our interests in the Delhi field. To take advantage of the EOR credits, we amended federal and state tax returns for the years ended June 30, 2017 and 2018 and incorporated the associated impacts into our 2019 tax returns. Principally as a result of the EOR credits, the Company recorded a net tax benefit of $2.8 million during the current year. Relative to the foregoing, the Company has a $3.2 million receivable for income tax refunds at June 30, 2020.

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. 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, 2020	% of Income Before Income Taxes	June 30, 2019	% of Income Before Income Taxes
Income tax provision (benefit) computed at the statutory federal rate:	$ 788,776	21.0 %	$ 3,960,480	21.0 %
Reconciling items:				
Return to provision adjustments including returns amended for EOR credits	(2,823,527)	(75.2)%	—	— %
Depletion in excess of tax basis	(412,215)	(11.0)%	(982,302)	(5.1)%
State income taxes, net of federal tax benefit	272,962	7.3 %	593,533	3.1 %
Permanent differences related to stock-based compensation and other	22,408	0.6 %	(73,671)	(0.4)%
Expiration of Section 382 tax loss carryforwards	—	— %	127,410	0.7 %
Change in valuation allowance for Section 382 tax loss carryforwards	—	— %	(127,410)	(0.7)%
Other	(29,400)	(0.8)%	(15,679)	(0.1)%
Income tax provision (benefit)	$ (2,180,996)	(58.1)%	$ 3,482,361	18.5 %

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, 2020	June 30, 2019
Deferred tax assets:		
Non-qualified stock-based compensation	$ 234,559	$ 159,090
Net operating loss carry-forwards	78,197	496,082
Derivative losses	401,382	—
Other	53,159	20,713
Gross deferred tax assets	767,297	675,885
Valuation allowance	(53,218)	(53,218)
Total deferred tax assets	714,079	622,667
Deferred tax liability:		
Oil and natural gas properties	(11,775,102)	(11,945,358)
Total deferred tax liability	(11,775,102)	(11,945,358)
Net deferred tax liability	$ (11,061,023)	$ (11,322,691)

As of June 30, 2020, we had a federal tax loss carryforward of approximately $0.6 million that we acquired through a 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, 2020	June 30, 2019
Numerator		
Net income attributable to common shareholders	$ 5,937,072	$ 15,377,066
Denominator		
Weighted average number of common shares – Basic	33,031,149	33,160,283
Effect of dilutive securities:		
Contingent restricted stock grants	1,942	9,435
Weighted average number of common shares and dilutive potential common shares used in diluted EPS	33,033,091	33,169,718
Net income per common share – Basic	$ 0.18	$ 0.46
Net income per common share – Diluted	$ 0.18	$ 0.46

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2020
Contingent Restricted Stock grants	$ —	200,000

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

Note 15 – 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.

On April 27, 2020, the Company completed its spring redetermination of the Facility resulting in a decrease of the borrowing base to $27 million. The Company's ability to access the borrowing base is also limited by its compliance with certain financial covenants, including a debt service ratio covenant, described below. As a consequence of declining oil prices adversely impacting the Company's EBITDA upon which the debt service ratio is calculated, at June 30, 2020 the Company's borrowings would have been limited to approximately $8 million. There are no borrowings outstanding under the Facility, which matures on April 11, 2021. The Facility is secured by substantially all of the reserves associated with the Delhi field.

As of June 30, 2020, the Company was in compliance with all financial covenants and there were no amounts outstanding under the Facility.

Under the Facility the borrowing base shall be determined semiannually as of every May 15 and November 15 during the term of the Facility.

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 $11,888 as of June 30, 2020.

Note 16 – Commitments and Contingencies

We are subject to various claims and contingencies in the normal course of business. 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 our business. 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, 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.

Note 17 – Concentrations of Credit Risk

Major Customers. As a non-operator, we presently market our production through the field operators. 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, 2020 and 2019. The loss of either one of our oil purchasers or disruption to their respective pipelines could adversely affect our net realized pricing and potentially our near-term production levels. The loss of our NGL purchaser, who trucks NGLs from the field, would not be expected to have a material adverse effect on our operations.

	Year Ended June 30,	
Customer	**2020**	**2019**
Plains Marketing L.P. (Delhi field oil)	87%	94%
Merit Energy Company (Hamilton Dome field oil)	10%	—%
Third Coast Midstream (Delhi field NGLs)	3%	6%
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 is available to 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, subject to IRS limits, with Company contributions fully vested when made. Our matching contributions to the Plan totaled $41,127 and $52,809 for the years ended June 30, 2020 and 2019, respectively.

Note 19 – Derivatives

It is the Company’s policy to enter into derivative contracts only with counterparties that are creditworthy financial or commodity hedging institutions deemed by management as competent and competitive market makers. As of June 30, 2020, the Company did not post collateral under its one open derivative contract as trades were uncollateralized.

The Company may utilize fixed-price swaps or costless put/call collars to hedge a portion of its anticipated future production. Fixed-price swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for the volumes under contract. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price. The Company has elected not to designate its open derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of the derivative contracts and all payments and receipts on settled derivative contracts in "Net (gain) loss on derivative contracts" on the consolidated statements of operations.

	Years Ended June 30,	
	2020	2019
Realized (gain) loss	$ (528,139)	$ —
Unrealized (gain) loss	1,911,343	—
Net (gain) loss on derivative contracts	$ 1,383,204	$ —

The Company's derivative contract is recorded at fair market value and is included in the consolidated balance sheets as an asset or a liability. Refer to Note 20 – Fair Value Measurement for the table summarizing the location and fair value amounts of the Company's open derivative contract in the consolidated balance sheet as of June 30, 2020. The Company did not have any open positions as of June 30, 2019.

The following sets forth a summary of the Company's open crude oil derivative positions as of June 30, 2020.

Period	Type of Contract	Volumes in Barrels	Price / Price Range	Weighted Average Floor Price per Bbl.	Weighted Average Ceiling Price per Bbl.
July 2020 to December 2020	Fixed-Price Swap	257,600	$32	$32	$—

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The Company enters into an International Swap Dealers Association Master Agreement ("ISDA") with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

Note 20 – 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 are little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair Value of Derivative Instruments. The Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 – Fair Value Measurement ("ASC 820") establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable (Level 1), market corroborated (Level 2), or generally unobservable (Level 3). The Company classifies fair value balances based on the observability of those inputs.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment; this may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for any period presented in this report. The table below sets forth the Company's derivative assets and liabilities whose fair value measurements all reflect Level 2 inputs as of June 30, 2020. The Company did not have any open positions at June 30, 2019.

	June 30, 2020		
Asset (Liability)	**Gross Amounts Recognized**	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts Presented in the Consolidated Balance Sheets**
Current derivative assets	$ —	—	$ —
Current derivative contract liabilities	1,911,343	—	1,911,343
Total	$ 1,911,343	—	$ 1,911,343

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 21 – 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, examining specific areas that are considered to have prospects containing oil and natural gas reserves, costs of drilling exploratory wells, geological and geophysical assessment 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 $918,137 and $86,384 during the years ended June 30, 2020 and 2019, respectively.

	For the Years Ended June 30,	
	2020	**2019**
Oil and Natural Gas Activities		
Property acquisition costs:		
Proved property	$ 9,337,716	$ —
Unproved property	—	—
Exploration costs	—	—
Development costs	2,430,510	5,229,235
Total costs incurred for oil and natural gas activities	$ 11,768,226	$ 5,229,235

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, 2020 and 2019, SEC methodology 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 crude oil, natural gas liquids , and natural gas reserves and changes in quantities of proved developed and undeveloped reserves for each of the periods indicated are as follows:

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
Proved developed and undeveloped reserves:				
June 30, 2018	8,090,190	1,277,772	—	9,367,962
Revisions of previous estimates (a)	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
Revisions of previous estimates (b)	(2,177,787)	734,169	—	(1,443,618)
Improved recovery, extensions and discoveries	—	—	—	—
Purchase of reserves in place (c)	3,426,756	—	—	3,426,756
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(638,464)	(106,340)	—	(744,804)
June 30, 2020	8,226,236	1,992,590	—	10,218,826
Proved developed reserves:				
June 30, 2018	6,291,850	993,741	—	7,285,591
June 30, 2019	6,273,907	1,124,302	—	7,398,209
June 30, 2020	6,577,731	1,777,236	—	8,354,967
Proved undeveloped reserves:				
June 30, 2018	1,798,340	284,031	—	2,082,371
June 30, 2019	1,341,824	240,459	—	1,582,283
June 30, 2020	1,648,505	215,354	—	1,863,859

(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) Primarily due to negative revisions at Hamilton Dome field reflecting the impact of pricing on future economic production. In March 2020 when the oil price decreased, the operator began to shut-in wells that were not economic at those lower prices to try and keep the field cash flow positive. The use of an SEC price deck for our reserves at June 30, 2020, precludes volumes that are uneconomic at such prices. Positive NGL revisions at Delhi field reflect adjusted methodology of forecasting NGLs independently from the oil production as forecasted by our independent reservoir engineering firm.

(c) On November 1, 2019, the Company acquired certain mineral interests in the Hamilton Dome field from Merit, who owns the vast majority of the remaining working interest in the field.

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales, 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 for 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, 2020 and 2019 are as follows:

	As of June 30,	
	2020	2019
Future cash inflows	$ 399,358,481	$ 524,037,200
Future production costs and severance taxes	(240,399,715)	(208,539,679)
Future development costs	(24,623,426)	(18,395,252)
Future income tax expenses	(21,982,469)	(55,881,997)
Future net cash flows	112,352,871	241,220,272
10% annual discount for estimated timing of cash flows	(49,862,035)	(114,488,230)
Standardized measure of discounted future net cash flows	$ 62,490,836	$ 126,732,042

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,			
	2020		2019	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$ 47.37	n/a	$ 61.62	n/a

There were no natural gas reserves in 2020 and 2019. 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.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	For the Years Ended June 30,	
	2020	2019
Balance, beginning of the fiscal year	$ 126,732,042	$ 118,958,414
Net changes in sales prices and production costs related to future production	(83,857,342)	23,753,518
Changes in estimated future development costs	(4,099,792)	833,494
Sales of oil and gas produced during the period, net of production costs	(16,093,794)	(28,962,837)
Net change due to extensions, discoveries, and improved recovery	—	—
Net change due to revisions in quantity estimates	(6,746,316)	6,129,847
Net change due to purchase of minerals in place	10,364,875	—
Development costs incurred during the period	1,431,444	2,089,139
Accretion of discount	16,266,663	14,604,387
Net change in discounted income taxes	17,078,591	(2,795,183)
Net changes in timing of production and other	1,414,465	(7,878,737)
Balance, end of the fiscal year	$ 62,490,836	$ 126,732,042

Note 22 – Selected Quarterly Financial Data (Unaudited)

2020	First	Second	Third (1)	Fourth
Revenues	$ 9,152,215	$ 9,381,615	$ 7,712,619	$ 3,352,847
Income (loss) from operations	$ 3,274,019	$ 2,249,764	$ 951,814	$ (2,786,164)
Net income (loss) attributable to common shareholders	$ 2,792,820	$ 1,764,918	$ 3,710,159	$ (2,330,825)
Basic earnings (loss) per common share	$ 0.08	$ 0.05	$ 0.11	$ (0.07)
Diluted earnings (loss) per common share	$ 0.08	$ 0.05	$ 0.11	$ (0.07)

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

(1) The third quarter of fiscal 2020 was impacted by a $2.8 million tax benefit attributable to the EOR tax credits.

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

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; this information is accumulated and communicated to this Company's management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely decisions regarding required disclosure.

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

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Generally accepted accounting principles include 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, 2020.

Effective April 27, 2020, the SEC adopted certain amendments to the accelerated filer and large accelerated filer definitions to more appropriately tailor the types of issuers that are included in the categories of accelerated and large accelerated filers and to promote capital formation, preserve capital, and reduce unnecessary burdens for certain smaller issuers while maintaining investor protections. As a result of the amendments, certain low-revenue issuers will remain obligated, among other things, to establish and maintain internal control over financial reporting and have management assess the effectiveness of its internal control over financial reporting, but they will not be required to have their management’s assessment of the effectiveness of internal controls over financial reporting attested to and reported on by an independent auditor. As a result, the effectiveness of our internal control over financial reporting at June 30, 2020 has not been audited by Moss Adams LLP, the independent registered public accounting firm that also audited our financial statements.

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, 2020 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 2020 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 2020 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 2020 fiscal year.

Item 13. Certain Relationships and Related Transactions, and 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 2020 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 2020 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 10, 2020	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 10, 2020	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 10, 2020	/s/ JASON E. BROWN Jason E. Brown	President and Chief Executive Officer (Principal Executive Officer)
September 10, 2020	/s/ DAVID JOE David Joe	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
September 10, 2020	/s/ RODERICK SCHULTZ Roderick Schultz	Vice President, Chief Accounting Officer (Principal Accounting Officer)
September 10, 2020	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 10, 2020	/s/ WILLIAM DOZIER William Dozier	Director
September 10, 2020	/s/ KELLY W. LOYD Kelly W. Loyd	Director
September 10, 2020	/s/ MARRAN H. OGILVIE Marran H. Ogilvie	Director

EXHIBIT INDEX

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 (previously filed as an exhibit to Form 10-K on September 13, 2019)
4.13	Form of Performance Share Unit Award Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (previously filed as an exhibit to Form 10-K on September 13, 2019)
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)

EXHIBIT NUMBER	DESCRIPTION
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)
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 (previously filed as an exhibit to Form 10-K on September 13, 2019)
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, 2020, on oil and gas reserves (SEC Case) dated August 10, 2020 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

List of Subsidiaries of Evolution Petroleum Corporation

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

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements (Form S-3/A No. 333-231412, Form S-3 No. 333-193899, Form S-8 Nos. 333-152136, 333-140182, 333-183746 and 333-216098) of Evolution Petroleum Corporation of our report dated September 10, 2020, relating to the consolidated financial statements of Evolution Petroleum Corporation, which report appears in the Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2020 (and expresses an unqualified opinion), and to the reference to our firm under the heading “Experts” in the Prospectuses, which are part of those Registration Statements.

/s/ Moss Adams LLP
Houston, Texas
September 10, 2020

DEGOLYER AND MACNAUGHTON
500 I SPRING ALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

September 10, 2020

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

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our report of third party dated August 10, 2020, and to the inclusion of information taken from our report entitled "Report as of June 30, 2020 on Reserves and Revenue of Certain Properties with interests attributable to Evolution Petroleum Corporation" in the Annual Report on Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2020. We further consent to the incorporation by reference of information in the Form 10-K in the Evolution Petroleum Corporation Registration Statements on Form S-8 (File Nos. 333-152136, 333-140182, 333-183746, and 333-216098), Form S-3/A (File No. 333-231412) and Form S-3 (File No. 333-193899).

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

EXHIBIT 31.1

CERTIFICATION

I, Jason E. Brown, President and Chief Executive Officer of Evolution Petroleum Corporation, certify that:

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

Dated: September 10, 2020

/s/ JASON E. BROWN
Jason E. Brown
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

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

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

Dated: September 10, 2020

/s/ DAVID JOE
David Joe
Chief Financial Officer

EXHIBIT 32.1

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

The undersigned, Jason E. Brown, President and Chief Executive Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2020 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has executed this certification as of September 10, 2020.

/s/ JASON E. BROWN
Jason E. Brown
President and *Chief* Executive *Officer*

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

EXHIBIT 32.2

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

The undersigned, David Joe, Chief Financial Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2020 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has executed this certification as of September 10, 2020.

/s/ DAVID JOE
David Joe
Chief Financial Officer

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

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

August 10, 2020

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

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of June 30, 2020, of the extent and value of the estimated net proved oil, natural gas liquids (NGL), and gas reserves of the Delhi field in Louisiana and the proved developed producing oil and gas reserves in the Hamilton Dome field in Wyoming in which Evolution Petroleum Corporation and its subsidiaries (collectively referred to herein as Evolution) have represented they hold an interest. This evaluation was completed on August 10, 2020. Evolution has represented that these properties account for 100 percent on a net equivalent barrel basis of Evolution's net proved reserves as of June 30, 2020. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a)(1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with the guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Evolution.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after June 30, 2020. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Evolution after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, carbon dioxide purchase expenses, transportation and processing expenses, compression charges, and overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Evolution to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with abandonment. At the request of Evolution, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

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

Information used in the preparation of this report was obtained from Evolution and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Evolution with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

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

> *Proved oil and gas reserves* – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> > (i) The area of the reservoir considered as proved includes:
> > (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
> >
> > (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
> >
> > (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
> > (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

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

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

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

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

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

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

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definition of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019." The method or combination of methods used in the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

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

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Evolution.

Evolution has represented that its senior management is committed to the development plan provided by Evolution and that Evolution has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. Certain properties evaluated herein are produced using enhanced oil recovery methods involving continuous carbon dioxide flooding operations. Therefore, carbon dioxide versus oil ratios and carbon dioxide injection volumes were analyzed and projected and were used in the estimation of reserves when applicable.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Data provided by Evolution from wells drilled through June 30, 2020, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available through June 30, 2020. Cumulative production, as of June 30, 2020, was deducted from the estimated gross ultimate recovery to estimate gross reserves.

Oil reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state in which the reserves are located. Gas quantities included in this report are expressed in millions of cubic feet (MMcf). All of the produced gas is consumed as fuel or lost in processing, so sales gas reserves were estimated herein to be zero.

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein are associated gas.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Evolution. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil and NGL Prices

Evolution has represented that the oil and NGL prices were based on West Texas Intermediate (WTI) pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil and NGL prices were calculated using differentials furnished by Evolution to the reference price of $47.37 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $46.37 per barrel of oil and $9.00 per barrel of NGL.

Production and Ad Valorem Taxes

Production taxes were calculated using rates provided by Evolution, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Evolution based on recent payments.

Evolution has represented that the Delhi carbon dioxide flood has been qualified as a tertiary recovery project and that no oil production taxes will be charged until certain investment and interest expenses have been paid out from the project revenue. Oil production taxes then revert to a 12.5-percent rate, which rate is held constant until average oil production per well drops below 25 barrels per day, and then reduced to 6.25 percent thereafter. Payout is not expected to occur prior to depletion, so no oil production taxes are included herein for the Delhi field.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Evolution and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2020 values, provided by Evolution, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Evolution and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

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

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

Summary of Conclusions

The estimated net proved reserves, as of June 30, 2020, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Estimated by DeGolyer and MacNaughton Net Reserves as of June 30, 2020		
	Oil (Mbbl)	NGL (Mbbl)	Sales Gas (MMcf)
Proved			
Developed	6,578	1,777	0
Undeveloped	1,648	216	0
Total Proved	**8,226**	**1,993**	**0**

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of June 30, 2020, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Future Gross Revenue	316,610	82,748	399,358
Production Taxes	2,899	34	2,933
Ad Valorem Taxes	5,258	662	5,920
Operating Expenses	189,074	42,473	231,547
Capital Costs	6,292	8,600	14,892
Abandonment Costs	9,054	677	9,731
Future Net Revenue	104,033	30,302	134,335
Present Worth at 10 Percent	67,264	8,029	75,293

Note: Future income taxes have not taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the June 30, 2020, estimated reserves.

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

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves

Gregory K. Graves, P.E.
Vice President
DeGolyer and MacNaughton

{SEAL}

CERTIFICATE of QUALIFICATION

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

1. That I am a Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Evolution Petroleum Corporation dated August 10, 2020, and that I, as Vice President, was responsible for the preparation of this report of third party.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 35 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves

Gregory K. Graves, P.E.
Vice President
DeGolyer and MacNaughton

{SEAL}