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, 2022

☐ **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**

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, 2021, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $5.05 on the NYSE American was $154.7 million.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 9, 2022, was 33,466,905.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2022 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
2022 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. All statements, except for statements of historical fact, that relate to the anticipated future activities, plans, strategies, objectives or expectations of the Company are forward-looking statements. The words “plan,” “expect,” “project,” “estimate,” “may,” “assume,” “believe,” “anticipate,” “intend,” “budget,” “forecast,” “predict” and other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words or phrases. 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. Forward-looking statements include statements regarding: expectations of plans, strategies and objectives of the Company, including anticipated development activity and capital spending; the Company’s capital allocation strategy, capital structure, anticipated sources of funding, growth in long-term shareholder value and ability to preserve balance sheet strength; the benefits of the Company’s multi-basin portfolio, including operational and commodity flexibility; the Company’s ability to maximize cash flow and the application of excess cash flows to reduce long-term debt and to pay dividends and repurchase shares pursuant to its Share Repurchase Program; oil, natural gas and NGLs production and commodity mix, GHG emissions and ESG performance; anticipated oil, natural gas and NGL prices; anticipated drilling and completions activity; estimates of the Company’s oil, NGLs and natural gas reserves and recoverable quantities; future interest expense; the Company’s ability to access credit facilities and other sources of liquidity to meet financial obligations throughout commodity price cycles; the Company’s ability to manage debt and financial ratios, finance growth and comply with financial covenants; the implementation and outcomes of risk management programs, including exposure to commodity price and interest rate fluctuations, the volume of oil, NGLs and natural gas production hedged, and the markets or physical sales locations hedged; the impact of changes in federal, state, provincial and local, rules and regulations; anticipated compliance with current or proposed environmental legislation, including the costs thereof; adequacy of provisions for abandonment and site reclamation costs; the Company’s operational and financial flexibility, discipline and ability to respond to evolving market conditions; the declaration and payment of future dividends and any anticipated repurchase the Company’s outstanding common shares; the adequacy of the Company’s provision for taxes and legal claims; the Company’s ability to manage cost inflation and expected cost structures, including expected operating, transportation, processing and labor expenses; the competitiveness of the Company against its peers, including with respect to capital, materials, people, assets and production; oil, NGL and natural gas inventories and global demand for oil, NGL and natural gas; the outlook of the oil and natural gas industry generally, including impacts from changes to the geopolitical environment; anticipated staffing levels; anticipated payments related to the Company’s commitments, obligations and contingencies, and the ability to satisfy the same; and the possible impact of accounting and tax pronouncements, rule changes and standards.

Readers are cautioned against unduly relying on forward-looking statements which, by their nature, involve numerous assumptions and are subject to both known and unknown risks and uncertainties (many of which are beyond our control) that may cause such statements not to occur, or actual results to differ materially and/or adversely from those expressed or implied. These assumptions include: future commodity prices and basis differentials; the ability of the Company to access credit facilities and shelf prospectuses; assumptions contained in the Company’s corporate guidance; the availability of attractive commodity or financial hedges and the enforceability of risk management programs; expectations that counterparties will fulfill their obligations pursuant to gathering, processing, transportation and marketing agreements; access to adequate gathering, transportation, processing and storage facilities; assumed tax, royalty and regulatory regimes; expectations and projections made in light of, and generally consistent with, the Company’s historical experience and its perception of historical industry trends; and the other assumptions contained herein.

Readers are cautioned that the assumptions, risks and uncertainties referenced above, and in the other documents incorporated herein by reference (if any), are not exhaustive. Although the Company believes the expectations represented by its forward-looking statements are reasonable based on the information available to it as of the date such statements are made, forward-looking statements are only predictions and statements of our current beliefs and there can be no assurance that such expectations will prove to be correct.

When considering any forward-looking statement, the reader 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. Readers should also consider such information in conjunction with our consolidated financial statements and related notes and Item 7. *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. Readers 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
Bbl	One stock tank barrel, of 42 U.S. gallons of liquid volume, used herein in reference to oil or NGL.
BCF	Billion cubic feet.
BFPD	Barrels of fluid per day.
BOE	Barrels of oil equivalent. BOE is calculated by converting six MCF of natural gas and 42 gallons of NGL to one Bbl of oil which reflects energy equivalence and not price equivalence. Natural gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.
BOEPD	Barrels of oil equivalent per day.
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 one degree Fahrenheit. One Bbl of oil 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 farmout 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 farmout may be structured as a sale or lease, depending on the specific rights and carved out interests retained by the assignor.
Gross Acres or Gross Wells	The total acres or number of wells participated in, regardless of the amount of working interest owned.
Horizontal Drilling	Involves drilling horizontally out from 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 natural gas.
LOE	Lease Operating Expense(s); a current period expense incurred to operate a well.
MBBL	One thousand barrels.
MMBBBL	One million barrels.
MBOE	One thousand barrels of oil equivalent.
MMBOE	One million barrels of oil equivalent.
MMBOEPD	One million barrels of oil equivalent per day.
MCF	One thousand cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature.
MMCF	One million cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature.
MMBTU	One million British Thermal Units.
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.
Non-operated Interest	An interest in an oil and/or natural gas property but does not participate in or have any responsibility for actual operation of the property.
Non-operated Working Interest	An interest in an oil and/or natural gas property but does not participate in or have any responsibility for actual operation of the property, but is burdened with the cost of development and operation of the property.
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 natural 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 natural 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 millidarcy. Extremely low permeability of 10 millidarcy, 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 darcy 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.
Primary Recovery Method	The extraction of oil and natural gas from reservoirs using natural or initial reservoir pressure combined with artificial lift techniques such as pumps.
Producing Reserves	Any category of reserves that have been developed and production has been initiated.*
Producing Well	Any well that has 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 natural gas sales pipeline.*
Proved Developed Producing Reserves (“PDP”)	Proved Reserves that have been developed and production has been initiated.*
Proved Reserves	Estimated quantities of oil, natural gas, and NGLs which geologic 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 natural gas reserves, present value means the estimated future net revenues computed by applying current prices of oil and natural gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and natural 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 natural 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.
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Royalty or Royalty Interest	The mineral owner's share of oil or natural gas production (typically between 1/8 and ¼), 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.
Secondary Recovery Method	The extraction of oil and natural gas from reservoirs utilizing water injection (waterflooding) in order to maintain or increase reservoir pressure and direct the displacement of oil into producing wells.
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 are 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").
Tertiary Recovery Method	The extraction of oil and natural gas from reservoirs which employs injection of gas, heat, or chemicals into the reservoir in order to change the physical properties of the oil and aid in its extraction, also known as Enhanced Oil Recovery (EOR).
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.*

Water Injection Well	A well which is used to inject water under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.
Working Interest	The interest in the oil and natural 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 iv.*

General

Evolution Petroleum Corporation is an independent energy company focused on maximizing total returns to its shareholders through the ownership of and investment in onshore oil and natural gas properties in the United States. Our long-term goal is to maximize total shareholder return from a diversified portfolio of long-life oil and natural gas properties built through acquisition and through selective development, production enhancement, and other exploitation efforts on our oil and natural gas properties.

Recent Developments

Dividend Declaration and Share Repurchase Program

On September 12, 2022, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2022. This represents a 20% increase over the $0.10 per common share dividend paid in the fourth quarter of fiscal year 2022. Also, on September 8, 2022, our Board of Directors authorized a share repurchase program, under which we are approved to repurchase up to $25 million of our common stock through December 31, 2024. We intend to fund any repurchases from working capital and cash provided by operating activities. As we continue to focus on our goal of maximizing total shareholder return, the Board of Directors along with the management team believe that a share repurchase program is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will depend on a variety of factors, including management's assessment of the intrinsic value of our common shares, the market price of our common stock, general market and economic conditions, and applicable legal requirements. The value of shares authorized for repurchase by our Board of Directors does not require us to repurchase such shares or guarantee that such shares will be repurchased, and the program may be suspended, modified, or discontinued at any time without prior notice.

Jonah Field Acquisition

On April 1, 2022, we acquired non-operated working interests in the Jonah Field in Sublette County, Wyoming (the "Jonah Field Acquisition"). After taking into account the deposit on the acquisition, customary closing adjustments and an effective date of February 1, 2022, cash consideration was $26.4 million. The acquired properties include an average net working interest of approximately 20% and an average net revenue interest of approximately 15% in 595 producing wells and approximately 950 net acres. The properties are operated by Jonah Energy ("Jonah"), an established operator in the geographic region.

Williston Basin Acquisition

On January 14, 2022, we acquired non-operated working interests in 73 producing wells in the Williston Basin with an average net working interest of approximately 39% and average net revenue interest of approximately 33% located on approximately 45,000 net acres (approximately 90% held by production) across Billings, Golden Valley, and McKenzie Counties in North Dakota (the "Williston Basin Acquisition"). After taking into account customary closing adjustments and an effective date of June 1, 2021, cash consideration was $25.2 million which includes cash expenses related to the acquisition. The properties are operated by Foundation Energy Management ("Foundation"), an established operator in the geographic region.

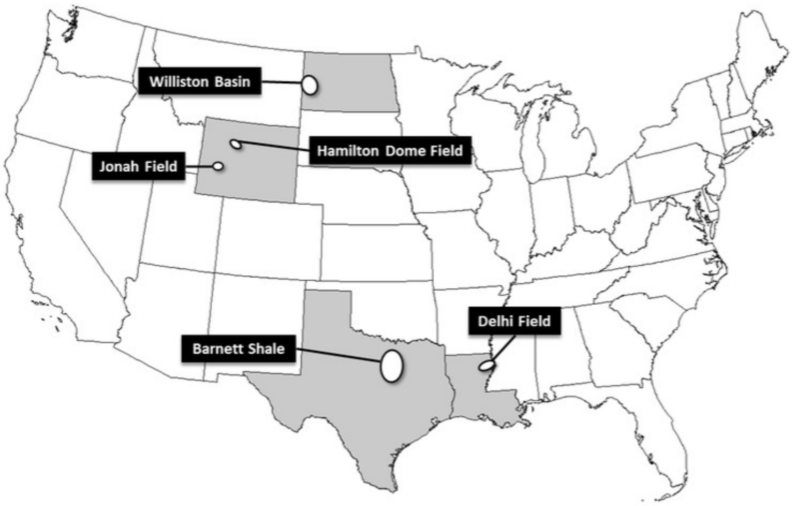
Business Strategy

Our business strategy is to maximize total shareholder return based on our assessment of the operating environment and marketplace, subject to our obligations to other stakeholders. The key elements of our strategy to accomplish our goal of maximizing shareholder return are:

- Maintaining a strong balance sheet and conservative financial management;
- Growing the asset base through investment in our existing properties, direct acquisitions of new low decline oil and natural gas properties, or accretive acquisitions of similar companies; and
- Returning cash to shareholders by sustaining and growing our dividend payout over time or repurchases of our shares in the open market.

Properties

Our oil and natural gas properties consist of non-operated interests in the Delhi Holt-Bryant Unit in the Delhi Field in Northeast Louisiana; the Hamilton Dome Field located in Hot Springs County, Wyoming; the Barnett Shale located in North Texas; the Williston Basin in North Dakota; the Jonah Field in Sublette County, Wyoming; and small overriding royalty interests in four onshore central Texas wells.



Delhi Field – Enhanced Oil Recovery CO_2 Flood – Onshore Louisiana

Our interests in the Delhi Field, a CO_2-EOR project, consist of approximately 24% average net working interest, with an associated 19% revenue interest and separate overriding royalty and mineral interests of approximately 7% yielding a total average net revenue interest of approximately 26%. The field is operated by Denbury Onshore LLC ("Denbury"), a subsidiary of Denbury Inc. The Delhi Field is located in northeast Louisiana in Franklin, Madison, and Richland Parishes and encompasses approximately 14,000 gross unitized acres, or approximately 3,200 net acres.

For the year ended June 30, 2022, our average net daily production from the Delhi Field properties was 1.2 MBOE per day ("MBOEPD") consisting of 81% oil and 19% natural gas liquids ("NGLs"). The primary producing reservoirs in the field are the Tuscaloosa and Paluxy formations. Produced oil from the field is priced off of Louisiana Light Sweet ("LLS") crude, which often trades at a premium to West Texas Intermediate ("WTI").

Hamilton Dome –Hot Springs County, Wyoming

Our interests in the Hamilton Dome Field, a secondary recovery field utilizing water injection wells to pressurize the reservoir, consists of approximately 24% average net working interest, with an associated 20% average net revenue interest (inclusive of a small overriding royalty interest). The approximately 5,900 gross acre unitized field, of which we hold approximately 1,400 net acres, is operated by Merit Energy Company ("Merit"), a private oil and natural gas company, who owns the vast majority of the remaining working interest in the Hamilton Dome Field. The Hamilton Dome Field is located in the southwest region of the Big Horn Basin in northwest Wyoming.

For the year ended June 30, 2022, our average net daily production from the Hamilton Dome Field properties was 0.4 MBOEPD consisting of 100% oil. The primary producing reservoirs in the field are the Tensleep and Phosphoria. Produced oil from the field is subject to Western Canadian Select pricing.

Barnett Shale - North Texas

On May 7, 2021, we acquired non-operated working interests in the Barnett Shale (the "Barnett Shale Acquisition"), a natural gas producing shale reservoir consisting of approximately 21,000 net acres held by production across nine North Texas counties (Bosque, Denton, Erath, Hill, Hood, Johnson, Parker, Somervell, and Tarrant), in the Barnett Shale. The acreage consists of an average net working interest of approximately 17% and associated average net revenue interest of approximately 14% (inclusive of small overriding royalty interests). The oil and natural gas properties are primarily operated by Diversified Energy Company with approximately 10% of wells operated by seven other operators.

For the year ended June 30, 2022, our average net daily production from the Barnett Shale properties was 3.5 MBOEPD consisting of 79% natural gas, 20% NGLs, and 1% oil. The producing reservoir is the Barnett Shale, which is also the source rock. Hydrocarbons produced from our Barnett Shale properties are sold to Gulf Coast markets.

Williston Basin – Williston, North Dakota

On January 14, 2022, we acquired non-operated working interests in 73 producing wells in the Williston Basin with an average net working interest of approximately 39% and average net revenue interest of approximately 33% located on approximately 45,000 net acres (approximately 90% held by production) across Billings, Golden Valley, and McKenzie Counties in North Dakota. The properties are operated by Foundation, an established operator in the geographic region.

Average net daily production from the date of acquisition through June 30, 2022 was 0.5 MBOEPD. For the year ended June 30, 2022, our average net daily production from the Willison Basin properties consisted of 81% oil, 11% NGLs, and 8% natural gas. The primary producing reservoirs are the Three Forks, Pronghorn, and Bakken formations. Hydrocarbons produced from the Williston Basin properties are sold to local refineries and purchasers.

Jonah Field – Sublette County, Wyoming

On April 1, 2022, we acquired non-operated working interests in the Jonah Field in Sublette County, Wyoming. The acquired properties include an average net working interest of approximately 20% and an average net revenue interest of approximately 15% in 595 producing wells and approximately 950 net acres all held by production. The properties are operated by Jonah Energy, an established operator in the geographic region.

Average net daily production from the date of acquisition through June 30, 2022 was 2.1 MBOEPD. For the year ended June 30, 2022 our average net daily production from the Jonah Field properties consisted of 88% natural gas, 7% NGL, and 5% oil. Hydrocarbons produced from our Jonah Field properties are sold to West Coast markets.

Refer to "*Production volumes, average sales price and average production costs*" table below for further information regarding our properties and their fiscal year results.

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

The Securities and Exchange Commission ("SEC") sets rules related to reserve estimation and disclosure requirements for oil and natural gas companies. These rules require disclosure of oil and natural 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 2022

Our proved reserves as of June 30, 2022, denominated in thousands of barrels of oil equivalent (MBOE), were estimated by our independent reservoir engineers, DeGolyer and MacNaughton ("D&M") and Netherland, Sewell & Associates, Inc. ("NSAI"), both worldwide petroleum consultants.

D&M evaluated the reserves for our Barnett Shale, Hamilton Dome, and Delhi Field properties. D&M, which was formed in 1936, has completed more than 23,000 projects in more than 100 countries. 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.

NSAI evaluated the reserves for our Williston Basin and Jonah Field properties. NSAI, which was founded in 1961, began evaluating these properties when we acquired each of them during the fiscal year ended June 30, 2022. The scope and results of their procedures are summarized in a letter from the firm, which is included as Exhibit 99.2 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved reserves as of June 30, 2022. For additional reserve information, see our *Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data*. The New York Mercantile Exchange ("NYMEX") previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $85.82 per barrel of oil and $5.19 per MMBtu of natural gas. The net price per barrel of NGLs was $44.24, 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, 2022

Reserve Category	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total Reserves (MBOE)[(1)]	Percent of Total Proved
Proved:					
Developed Producing	8,705	104,723	6,299	32,458	89.6 %
Developed Non-Producing	157	71	19	188	0.5 %
Undeveloped	2,608	2,197	623	3,597	9.9 %
Total Proved	11,470	106,991	6,941	36,243	100.0 %
Product Mix	32%	49%	19%	100%	
Total Proved by Property:					
Delhi Field	4,159	—	1,797	5,956	16.4 %
Hamilton Dome Field	2,374	—	—	2,374	6.6 %
Barnett Shale	96	65,619	3,649	14,682	40.5 %
Williston Basin	4,472	3,709	1,012	6,102	16.8 %
Jonah Field	369	37,663	483	7,129	19.7 %
Total Proved	11,470	106,991	6,941	36,243	100.0 %

(1) Equivalent oil reserves are defined as six Mcf of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per Mcf and NGL prices per barrel often differ significantly from the equivalent amount of oil.

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 internal reserve engineering team, which includes third-party consultants. Our internal reserve engineering team and third-party consultants have a combined experience of over 80 years in Petroleum Engineering. The person responsible for overseeing the preparation of our reserves estimates has a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, is a registered Professional Engineer in the State of Texas, has over 40 years of oil and natural gas experience including large independents and financial firm services for projects and acquisitions. Our Board of Directors also has oversight of our reserve estimation process and contains an independent director who is a Registered Professional Engineer with experience in energy company reserve evaluations. Such reserve estimates comply 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 and NSAI. The person responsible for the preparation of the reserve report at D&M is Dilhan Ilk, Senior Vice President and Division Manager of North America. Dr. Ilk received a Bachelor of Science degree in Petroleum Engineering in 2003 from Istanbul Technical University and a Master's degree and Doctorate in Petroleum Engineering in 2005 and 2010, respectively, from Texas A&M University, and he has in excess of 10 years of experience in oil and natural gas reservoir studies and evaluations. The person responsible for the preparation of the reserve report at NSAI is Steven W. Jansen, P.E., Vice President. Mr. Jansen, a Licensed Professional Engineer in the State of Texas (No. 112973), has been practicing consulting petroleum engineering at NSAI since 2011 and has over four years of prior industry experience. He graduated from Kansas State University in 2007 with a Bachelor of Science Degree in Chemical Engineering.

We provide D&M and NSAI with our property interests, production, current operating costs, current production prices, estimated abandonment costs and other information in order for them to prepare the reserve estimates. This information is reviewed by our senior management team, designated operations personnel, and third-party consultants to ensure accuracy and completeness of the data prior to submission to the reserve engineers. The scope and results of D&M's and NSAI's procedures, as well as their professional qualifications, are summarized in the letters included as Exhibit 99.1 and Exhibit 99.2, respectively, to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

During the year ended June 30, 2022 our proved undeveloped ("PUD") reserves changed as follows:

Proved undeveloped reserves:	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total Reserves (MBOE)[(1)]
June 30, 2021	1,605	—	208	1,813
Revisions of previous estimates	(1,605)	—	(208)	(1,813)
Improved recovery, extensions and discoveries	2,608	2,197	623	3,597
June 30, 2022	2,608	2,197	623	3,597

(1) Equivalent oil reserves are defined as six Mcf of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per Mcf and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Our PUD reserves were 3.6 MMBOE as of June 30, 2022, with related future development costs of approximately $61.7 million, which are associated with the Williston Basin properties. At June 30, 2021, our PUD reserves were 1.8 MMBOE, which were associated with Test Site V at our Delhi Field. PUD reserves associated with Test Site V were removed in the fiscal year ended June 30, 2022. The technical and economic merits of Test Site V remain attractive; however, the operator does not currently have Test Site V on its expenditure schedule for the next five years and, as a result, has been excluded from our proved reserves at this time. See "*Drilling and Present Activities*" below for a further discussion of our expected development of the PUDs added for the Williston Basin properties.

Drilling and Present Activities

Currently, none of our oil and natural gas properties are operated by us. We therefore rely on information from our operators regarding near-term drilling programs. As certain of our properties are considered fully developed, there are no plans to drill wells in fiscal year 2023 in the Hamilton Dome Field, the Delhi Field and the Jonah Field. At this time, operators of our Delhi Field, Hamilton Dome Field, Barnett Shale, Williston Basin, and Jonah Field properties are running workover rigs focusing on projects to return previously shut-in wells to production.

During fiscal year 2022, we participated in the drilling of two gross wells in Barnett Shale which were brought online during the fourth quarter of the fiscal year. Our net interest in each of these wells is approximately one percent or less. There are currently no plans to participate in the drilling of additional wells in the Barnett Shale in fiscal year 2023.

In the latter half of fiscal year 2022, our management team and third-party consulting engineers performed a technical review of drilling locations on our Williston Basin properties. Currently, there are 20 PUD drilling locations in the Pronghorn and Three Forks formations attributed to these properties. Pursuant to agreements we have with the operator, Foundation, we can propose drilling wells, in which the operator may participate. In the event the operator does not participate in our proposed drilling well, we have the right to undertake all necessary activities to drill, complete and install related facilities for the well. Ongoing operations of any well we elect to drill will be turned over to the operator of the property upon completion.

Our operator, Foundation, has also identified four PUD sidetrack locations in the Williston Basin targeting the Birdbear formation. Our management team and third-party consulting engineers have reviewed Foundation's plans and technical justification and plan to participate in the drilling of two of these wells during fiscal year 2023 and included the expected cost in our fiscal year 2023 capital budget.

For further discussion, see "Highlights for our Fiscal Year 2022" and "Capital Expenditures" within Item 7. *Management's Discussion and Analysis of Financial Conditions and Results of Operations*.

Production volumes, average sales price and average production costs

The following table summarizes our crude oil, natural gas, and natural gas liquids production volumes, average sales price per unit, average daily production on an equivalent basis, production costs, and production costs per unit for the periods indicated:

	Years Ended June 30,					
	2022		2021		2020	
	Volume	Price	Volume	Price	Volume	Price
Production:						
Crude oil (MBBL)						
Delhi Field	358	$ 86.57	410	$ 49.43	540	$ 47.63
Hamilton Dome Field	150	76.03	143	42.23	98	29.18
Barnett Shale	9	82.56	2	52.50	—	—
Williston Basin	71	101.25	—	—	—	—
Jonah Field	10	112.50	—	—	—	—
Other	21	58.57	—	—	—	—
Total	619	$ 85.11	555	$ 47.59	638	$ 44.79
Natural gas (MMCF)						
Barnett Shale	6,087	$ 5.11	963	2.73	—	—
Williston Basin	40	6.30	—	—	—	—
Jonah Field	1,000	7.80	—	—	—	—
Other	14	1.21	—	—	1	2.00
Total	7,141	$ 5.49	963	$ 2.73	1	$ 2.00
Natural gas liquids (MBBL)						
Delhi Field	83	$ 48.02	93	$ 18.95	106	$ 9.60
Barnett Shale	256	46.91	78	24.37	—	—
Williston Basin	10	38.50	—	—	—	—
Jonah Field	12	52.92	—	—	—	—
Other	3	18.33	—	—	—	—
Total	364	$ 46.89	171	$ 21.42	106	$ 9.60
Equivalent (MBOE) [(1)]						
Delhi Field	441	$ 79.32	503	$ 43.80	646	$ 41.39
Hamilton Dome Field	150	76.03	143	42.23	98	29.18
Barnett Shale	1,280	34.27	241	19.23	—	—
Williston Basin[(2)]	88	88.93	—	—	—	—
Jonah Field[(2)]	189	50.57	—	—	—	—
Other	25	52.08	—	—	—	—
Total	2,173	$ 50.13	887	$ 36.87	744	$ 39.78
Average daily production (BOEPD) [(1)]						
Delhi Field	1,208		1,378		1,765	
Hamilton Dome Field	411		392		268	
Barnett Shale	3,507		660		—	
Williston Basin	241		—		—	
Jonah Field	518		—		—	
Other	68		—		—	
Total	5,953		2,430		2,033	
Production costs (in thousands, except per BOE)						
Lease operating costs	Amount	per BOE	Amount	per BOE	Amount	per BOE
Delhi Field	$ 14,933	$ 33.86	$ 9,463	$ 18.81	$ 10,659	$ 16.50
Hamilton Dome Field	5,480	36.53	4,080	28.53	2,835	28.93
Barnett Shale	22,825	17.83	3,028	12.56	—	—
Williston Basin	2,419	27.49	—	—	—	—
Jonah Field	2,990	15.82	—	—	—	—
Other	10	0.40	16	—	12	—
Total	$ 48,657	$ 22.39	$ 16,587	$ 18.69	$ 13,506	$ 18.15

(1) Equivalent oil reserves are defined as six Mcf of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per Mcf and NGL prices per barrel often differ significantly from the equivalent amount of oil.

(2) Average daily production presented in the table above represents our fiscal year production divided by 365 days in the year. At Williston and Jonah, our average daily production since their respective acquisition dates of January 14, 2022 and April 1, 2022 through June 30, 2022, was 0.5 MBOEPD and 2.1 MBOEPD, respectively.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we own a working interest as of June 30, 2022.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	344	83.4	344	83.4
Natural gas	—	—	1,455	209.7	1,455	209.7
Total	—	—	1,799	293.1	1,799	293.1

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2022. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would allow production of oil and natural 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 natural gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total	
Field[(1)]	Gross	Net	Gross	Net	Gross	Net
Delhi Field, Louisiana	9,126	2,180	4,510	1,077	13,636	3,257
Hamilton Dome Field, Wyoming	5,908	1,389	—	—	5,908	1,389
Barnett Shale, Texas	123,777	20,918	—	—	123,777	20,918
Williston Basin, North Dakota	124,800	37,306	23,680	7,389	148,480	44,695
Jonah Field, Wyoming	5,280	956	—	—	5,280	956
Total[(2)]	268,891	62,749	28,190	8,466	297,081	71,215

(1) Except for our undeveloped acreage in Williston Basin, North Dakota (see expiration table below), 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 late fiscal year 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.

We acquired the Williston Basin properties on January 14, 2022. The table below reflects our net undeveloped acreage in Williston Basin, North Dakota as of June 30, 2022 that will expire each year if we do not establish production in paying quantities on the units in which such acreage is included to maintain the lease:

Fiscal Year	**Net Acreage Expiration**[(1)]
2023	1,369
2024	440
2025	1,664
2026	860
2027 & beyond	309
	4,642

(1) Excluded 2,747 net acres held by existing production as long as continuous production is maintained in the unit.

Markets and Customers

Our production is marketed to third parties in a manner consistent with industry practices. In the United States market where our properties are operated, crude oil, natural gas, and NGLs are readily transportable and marketable. In the

Jonah Field, we take our natural gas and NGL working interest production in-kind and market separately to purchasers on six-month contracts for natural gas and to Enterprise Products Partners L.P. for NGLs. We do not currently market our share of oil, natural gas, or NGLs production from the Delhi Field, the Hamilton Dome Field, the Barnett Shale or the Williston Basin 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.

As a non-operator, we are highly dependent on the success of our third-party operators and the decisions made in connection with their operations. The third-party operator sells the oil, natural gas, and NGLs to the purchaser, collects the cash, and distributes the cash to us. In the years ended June 30, 2022 and 2021, three operators each distributed over 10% of our oil, natural gas and NGL revenues making up approximately 83% and 100% of total revenues for the years, respectively.

As the acquisition of the Williston Basin and Jonah Field properties occurred in the second half of fiscal year 2022, we expect purchases of our crude oil, natural gas, and NGL production from these properties to represent a larger percentage of total sales in fiscal year 2023 and beyond. The loss of a purchaser at any of our five major producing properties or disruption to pipeline transportation from these fields could adversely affect our net realized pricing and potentially our near-term production levels.

Market Conditions

Prices we receive for crude oil, natural gas, and NGLs 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, weather, and actions of major foreign producers.

Oil prices over the past few years have fluctuated widely and been extremely volatile. For example, average daily prices for WTI oil ranged from a high of $123.64 per barrel to a low of $35.64 per barrel over our last two fiscal years. The price of oil per barrel dropped substantially in fiscal 2020 as a result of the impact of the novel coronavirus ("COVID-19") pandemic and geopolitical factors but recovered to an average of $108.83 per barrel during the fiscal fourth quarter of 2022. The severe drop in oil price during the pandemic and market share competition between OPEC+ members in the spring of 2020 substantially and adversely impacted oil, natural gas, and NGL prices during the balance of 2020, and thus impacted the trailing 12-month commodity prices required for reserves and ceiling tests for asset carrying value which in turn led to substantial impairments during our first and second quarters of fiscal 2021. Worldwide factors such as global health pandemics, geopolitical, international trade disruptions and tariffs, macroeconomics, supply and demand, refining capacity, petrochemical production, and derivatives trading, among others, influence prices for oil, natural gas, and NGLs. Local factors also influence prices for oil, natural gas, and NGLs 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 oil and natural gas companies, numerous independent oil and natural gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staff 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 geologic systems and the ability to efficiently conduct operations, achieve technological advantages, identify and acquire economically producible reserves, and obtain capital at rates that allow economic investments.

Risk Management

We are exposed to certain risks relating to our ongoing business operations, including commodity price risk. In accordance with our company policies and the covenants under the Senior Secured Credit Facility, 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 do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivative instruments available, we typically use costless collars and fixed-price swaps to attempt to manage price risk. 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. 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.

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. We will continue to evaluate the benefit of employing derivatives in the future. Our hedge policies and objectives may change as our operational profile changes. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and Note 8, *"Derivatives"* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* for additional information.

Government Regulation

As an oil and natural gas exploration and production company, our interests are subject to numerous legal requirements.

Regulation of Oil and Natural Gas Production

Federal, state, tribal and local authorities have promulgated extensive rules covering oil and natural gas exploration, production and related operations. Those regulations require our operating partners to obtain permits, post bonds and submit reports. They also may address conservation, including unitization or pooling of oil and natural gas properties, well locations, the method of drilling and casing wells, surface use and restoration of properties where wells are drilled, sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce and to limit the number of wells or the locations at which we can produce. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any applicable legal requirements may result in substantial penalties. Because such regulations are frequently amended or reinterpreted, we are unable to predict future compliance costs or impacts. Significant expenditures may be required to comply with governmental laws and regulations, however, and may have a material adverse effect on our financial condition and results of operations.

Regulation of Transportation of Oil and Natural Gas

The prices for crude oil, condensate and natural gas liquids and natural gas are negotiated and not currently regulated. But Congress, which has been active in oil and natural gas regulation, could impose price controls in the future.

Our sales of crude oil and natural gas are affected by the availability, terms and cost of transportation. The Federal Energy Regulatory Commission ("FERC") primarily regulates interstate oil and natural gas transportation rates. In some circumstances, FERC regulations also may affect intrastate pipelines. In addition, states may impose on intrastate pipelines various obligations relating to such matters as safety, environmental protection, nondiscriminatory take and rates. The basis for intrastate oil and natural gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to such matters, vary from state to state. To the extent effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil and natural gas transportation rates will not affect our business in any way that is of material difference from those of our competitors who are similarly situated.

Environmental Matters

Our properties are subject to extensive and changing federal, state and local laws and regulations relating to protection of the environment, worker safety and human health. Such requirements may address:

- the generation, storage, handling, emission, transportation and disposal of materials;
- reclamation or remediation of sites, including former operating areas;
- the acquisition of a permit or other authorization;
- air emissions;
- protection of water supplies;
- limits on construction, drilling and other activities in wilderness or other environmentally sensitive areas; and
- assessment of environmental impacts.

Failure to comply with such requirements may result in a variety of sanctions, including, fines, administrative orders and injunctions. In addition, issuing authorities may revoke, adversely modify or deny permits necessary for our operations. In the opinion of management, our properties are in substantial compliance with applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general. Significant environmental requirements that may affect our operations are described below.

The Comprehensive Environmental, Response, Compensation, and Liability Act ("CERCLA") and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for neighboring landowners or other third parties to also file claims for personal injury and property damage allegedly caused by any hazardous substances released into the environment. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," our operations do entail handling other chemicals that may be subject to the statute. In addition, state laws affecting our properties may impose cleanup liability relating to petroleum and petroleum related products. The Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste." Violations may result in substantial fines. Although RCRA currently classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous, thereby subjecting our operations to more stringent handling and disposal requirements. In some circumstances, moreover, RCRA authorizes both the federal government and private persons to seek injunctions requiring the cleanup of wastes, whether hazardous or non-hazardous.

The Endangered Species Act ("ESA") protects fish, wildlife and plants that are listed as threatened or endangered. Under the ESA, exploration and production operations may not significantly impair or jeopardize a protected species or its habitat. The ESA provides for criminal penalties for willful violations. Our operations also may be subject to other statutes that protect animals and plants such as the Migratory Bird Treaty Act. Although we believe that our properties are in compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our operating partners) to significant expenses to modify operations, could force discontinuation of certain operations altogether and could limit the locations our operating partners may utilize in the future.

The Clean Air Act ("CAA") is the comprehensive federal law addressing sources of air emissions. Oil and natural gas production and natural gas processing operations are among the many source categories subject to the CAA. Regulated emissions from oil and natural gas operations include sulfur dioxide, volatile organic compounds ("VOCs") and hazardous air pollutants such as benzene, among others.

In particular, the Environmental Protection Agency ("EPA") proposed in November 2021 to impose new CAA rules restricting methane (a greenhouse gas) and VOC emissions from new, existing and modified facilities in the oil and gas sector. Among other things, EPA's proposed new rule would require states to implement plans that meet or exceed established emission reduction guidelines for oil and natural gas facilities. These regulations and proposals and any other new regulations requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations and financial condition.

The Clean Water Act (the "CWA") is the primary federal law controlling the discharge of produced waters and other pollutants into waters of the United States. Permits must be obtained for such discharges and to conduct construction activities in waters and wetlands. Some states also require permits for discharges or operations that may impact groundwater.

The CAA, CWA and comparable state statutes authorize civil, criminal and administrative penalties for violations. Further, the CWA and Oil Pollution Act may impose liability on owners or operators of onshore facilities that impact surface waters.

Pursuant to the Safe Drinking Water Act, EPA (or an authorized state) regulates the construction, operation, permitting, and closure of injection wells used to place oil and natural gas wastes and other fluids underground for storage or disposal. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Underground injection associated with oil and gas operations, particularly the disposal of produced water, has been linked in some cases to localized earthquakes. This in turn has led to new legislative and regulatory initiatives, which have the potential to restrict injection in certain wells or limit operations in certain areas.

Substantially all of the oil and natural gas production in which we have an interest is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection into the formation of water, sand and chemicals under pressure to stimulate production. From time to time, legislation has been proposed in the United States Congress to repeal the Safe Drinking Water Act's exemption for hydraulic fracturing from the definition of "underground injection" and to require federal permitting of hydraulic fracturing. If ever enacted, such legislation would add to our production costs.

Scrutiny of hydraulic fracturing activities continues in other ways. Several states where our properties are located have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities likewise have enacted bans on hydraulic fracturing. We cannot predict whether any other legislation restricting hydraulic fracturing will be enacted and if so, what its provisions would be. If additional levels of regulation and permits were to be required through the adoption of new laws and regulations at the federal, state, tribal or local level, it could lead to delays, increased operating costs and process prohibitions that could materially adversely affect our revenue and results of operations.

The National Environmental Policy Act ("NEPA") requires federal agencies to assess the environmental effects of their proposed actions prior to making decisions. Among the broad range of actions covered by NEPA are decisions on permit applications and federal land management. Many of the activities of our third-party operating partners involve federal decisions subject to NEPA. Such federal actions may trigger robust NEPA review, which could lead to delays and increased costs that could materially adversely affect our revenues and results of operations. In 2022, moreover, the Biden Administration reversed changes to NEPA rules enacted under the Trump Administration that had been intended to streamline NEPA review. The revised regulations lay the foundation for additional scrutiny of impacts on climate change, which could affect the assessment of projects ranging from oil and gas leasing to development on public and Indian lands.

Climate Change

Climate change has become a major public concern and policy issue in the United States and around the world. Much of the debate has focused on greenhouse gas ("GHG") emissions from oil and natural gas, particularly carbon dioxide and methane.

In the United States, there is no comprehensive federal regulatory statute addressing climate change, although Congress does periodically consider such measures. At the federal level, the United States therefore has primarily addressed climate change through executive actions and regulatory initiatives pursuant to existing statutes. These include rejoining the Paris Agreement on climate change, the Biden Administration's commitment to cut greenhouse gas emissions by 2030 to 50-52 percent of 2005 levels, various executive orders, limiting land available for oil and gas leasing, the United States Methane Emissions Reduction Action Plan, and Clean Air Act rules (such as the November 2021 proposal to regulate methane from the oil and gas sector). In addition, several states have already implemented or are considering programs to reduce GHG emissions. These include cap and trade programs, promotion of alternative forms of energy, transportation standards and restrictions on particular GHGs. To the extent that new climate change measures are adopted, and our third-party operating partners must further control GHG emissions, our business may be adversely impacted.

In addition, recent court decisions have left open the question of whether tort claims alleging property damage may proceed against sources of GHG emissions under state common law. Thus there is some litigation risk for such claims.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources, for example, our products would become more desirable in the market with more stringent limitations on GHG emissions. But in 2022, the United States enacted the Inflation Reduction Act that, among other things, creates a series of financial incentives intended to discourage use of oil and natural gas (including imposing a fee on methane emissions) and to promote alternative sources of energy. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products may become less desirable in the market with such government intervention. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Various studies on climate change indicate that extreme weather conditions and other risks may occur in the future in the areas where we operate. Although we have not experienced any material impact from such extreme conditions to date, no assurance can be given that they will not have a material adverse effect on our business in the future.
See discussion captioned "Government regulation and liability for oil and natural gas operations and environmental matters may adversely affect our business and results of operations" in Item 1A. *Risk Factors*.

Insurance

We maintain insurance on our oil and natural gas properties and operations for risks and in amounts customary in the industry. Such insurance includes, but is not limited to, 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 business interruption or lost profits coverage.

Human Capital, Sustainability, and ESG

Employees

As of June 30, 2022, we had eight full-time employees, not including contract personnel and outsourced service providers. We believe that we have positive relations with our employees. Our team is broadly experienced in oil and natural 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. For our full-time employees, our benefits package, as determined by our Board of Directors, includes medical, dental, and vision insurance, 401(k) contributions based on a portion of the employee's base salary, short and long-term performance-based and service-based incentive pay (i.e., annual bonuses and stock awards), and paid time off.

Our workforce is provided with annual training and is expected to sign an acknowledgement regarding our policies and disclosures which include, but are not limited to, the Corporate Sustainability Report ("CSR"), employee handbook, human rights, code of ethics, health and safety, emergency procedures, conflicts of interest, insider trading, bribery, kickbacks, discrimination, diversity, equality, and inclusion.

Sustainability and ESG

In fiscal year 2021, we formed an Environmental Social Governance ("ESG") Task Force. Under the supervision of our Board of Directors, the Nominating and Corporate Governance committee, and senior management, the ESG task force is responsible for the creation and implementation of our CSR and ESG initiatives. Evolution's inaugural CSR was published in November 2021. This report is accessible on our website at www.evolutionpetroleum.com.

The ESG Task Force has formalized our existing ESG programs, proposed and implemented new ESG initiatives, monitored adherence to ESG standards, and provided public disclosures for our stakeholders. In fiscal year 2022, the ESG Task Force continued to disclose, enhance, implement, and provide training for a number of new and existing policies and procedures. These include, but are not limited to: formalizing and implementing charitable donation program and employee volunteer initiative, completing our first annual company-wide ESG training program for both the Board of Directors and our workforce, implementation of safety inspections and health and safety coordinators, and incorporating ESG considerations into our compensation structure.

We are committed to high standards of conduct and ethics in order to contribute to the sustainability of our business. Our core values are the base to support our strategy and long-term success. We believe integrity is paramount and we are committed to develop and produce energy resources in environmentally, socially, and ethically respectful and responsible ways. Our people are critical to our success and as such we promote and maintain a safe and inclusive work environment. We strategically plan for the long-term and strive to maintain capital discipline and stakeholder transparency and continuous focus on returning capital to shareholders. We work with third-party operators that share our desire to operate and work responsibly, particularly for the natural environments in which they operate.

As a non-operator of our current properties, we do not have direct control over environmental initiatives at a property-level. However, we believe it is important to partner with third-party operators that share our core values and are committed to being environmental stewards as they responsibly produce energy resources. We recognize that the expectations, requirements, and responsibilities of operators regarding safeguarding the environment and environmental stewardship continue to evolve. We are, and will continue to be, committed to supporting our third-party operators as they respond to these expectations, requirements, and responsibilities.

At present, we do not report or collect data regarding emissions, water use, waste generation, spills, or other similar measurements on behalf of our operating partners. We host regular operations meetings with our operating partners in which we discuss asset level operations, expenses, any environmental issues and compliance, as well as ESG and health and safety related topics.

We do not report Scope 1 GHG, or direct, emissions to the EPA as we are not the operator of our properties, nor do we have financial control over our oil and natural gas properties and operations. We prefer to partner with third-party operators that work to reduce their Scope 1 GHG emissions, and we encourage them to accelerate their efforts as appropriate in this regard. As a non-operator, the Company reports in its CSR the estimated Scope 2 GHG emissions for its corporate office located in Houston, Texas. Scope 2 GHG emissions are based on indirect emissions representing purchased electricity. We are one of many tenants leasing space in our corporate office building and do not know the actual amount of electricity used in our space. As such, we estimate our consumption by multiplying the electricity purchased for the entire building by the percentage of the floor area that we occupy. Water use is also reported in the CSR and is calculated in a similar fashion.

We maintain a hotline which operates 24/7/365 and allows anonymous and confidential reporting for employees, consultants, partners, and contractors, including the ability to report concerns or violations of our policies through the phone or internet (Phone: 877-628-7489 / Website: www.epm.alertline.com).

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at www.evolutionpetroleum.com. These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, or calling

(713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk Factors

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

Risks Related to Our Business:

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

The price we receive for our oil and natural gas significantly influences our revenue, profitability, access to capital, capital spending, and future rate of growth. At June 30, 2022, approximately 32% of our proved reserves were oil reserves, 49% were natural gas and 19% were NGLs. Oil, natural gas and NGLs are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, over our last two fiscal years average daily prices for WTI oil ranged from a high of $123.64 per barrel to a low of a $35.64 per barrel, and Henry Hub natural gas prices ranged from a high of $23.86 to a low of $1.33 per MMBTU. Historically, the markets for oil, natural gas, and NGLs 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;
- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the conflict between Ukraine and Russia, and acts of terrorism or sabotage;
- the ability and willingness of the members of OPEC+ to agree and maintain oil price and production controls;
- the price and quantity of imports of foreign oil and natural gas;
- governmental, scientific, and public concern over the threat of climate change arising from greenhouse gas emissions;
- 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, natural disasters, and seasonal trends;
- domestic and foreign governmental regulations, including embargoes, sanctions, tariffs, and environmental 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;
- increasing attention to Environmental Social Governance ("ESG") matters; and
- the price, availability and use 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, natural gas, and NGL 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, natural gas, and NGL prices may also reduce the amount of oil, natural gas, and NGL that we can produce economically, which could lead to a decline in our oil, natural gas and NGL reserves. Generally, we hedge substantially less than all of our anticipated oil and natural gas production and typically only with the requirements of our Senior Secured Credit Facility. To the extent that we have not hedged production, any significant and extended decline in oil, natural gas, and NGL prices may adversely affect our financial position.

Our existing oil and natural gas production will decline; we may be unable to acquire or develop the additional oil and natural gas reserves that are required in order to sustain our production and business operations.

The volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Environmental issues, operating problems, or lack of extended future investment in any of our properties would cause our net production of oil, natural gas, and NGLs to decline significantly over time, which could have a material adverse effect on our financial condition.

The types of resources we focus on have substantial operational risks.

Our business plan focuses on the acquisition and development of known resources in partially depleted, naturally fractured, or low permeability reservoirs. Our Delhi Field and Hamilton Dome Field properties produce from relatively shallow reservoirs, while our Barnett Shale, Williston Basin and Jonah Field properties produce from deeper reservoirs. Shallower reservoirs usually have lower pressure, which generally translates into lower reserves volumes in place. Deeper reservoirs have higher pressures and usually more reserves volumes in place, but capturing those reserves often comes at increased drilling and completion costs and risks and, generally, a higher rate of production decline. Low permeability reservoirs require more wells and substantial stimulation for development of commercial production. Naturally fractured reservoirs require penetration of sufficient un-depleted fractures to establish commercial production. Depleted reservoirs require successful application of newer, or more expensive, technologies to produce incremental reserves. Our approach on the development and application of technologies on these different types of reservoirs could have a material adverse effect on our results of operations.

The CO_2-EOR project in the Delhi Field, operated by Denbury, 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 the Delhi Field in November 2009, initial oil production response began in March 2010. Additional capital remains to be invested to fully develop the EOR project and maximize the value of the properties. The operator's failure to manage these and other technical, environmental, operational, strategic, financial, and logistical risks may ultimately cause 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 our results of operations and financial condition.

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

All of our property interests are operated by third-party working interest owners, not by us. As a result, we have limited ability to influence or control the operations or future development of such properties, including compliance with environmental, safety, and other standards, 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 condition and results of operations.

We will be subject to risks in connection with acquisitions.

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 at the ground surface or otherwise when an inspection is performed. 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 and, importantly, that our assumptions regarding future oil and natural gas prices, differentials, reserves, or production could prove materially inaccurate and have a material adverse effect on our financial condition, results of operations, or cash flows.

We may encounter difficulties integrating the operations of newly acquired oil and natural gas properties or businesses.

Increasing our reserve base through acquisitions has been an important part of our business strategy. We may encounter difficulties integrating newly acquired oil and natural gas properties or businesses. In particular, we may face significant challenges in consolidating functions and integrating procedures, personnel, and business operations in an effective manner. The failure to successfully integrate such properties or businesses into our Company may adversely affect our business and results of operations. Any acquisition we make may involve numerous risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial costs to address unforeseen environmental and other liabilities arising out of the acquired businesses or assets;
- liabilities arising from the operation of the acquired businesses or assets before our acquisition;
- our lack of drilling or operational history in the areas in which the acquired business operates;
- customer or key employee loss from the acquired business;
- increased administration of new personnel;
- additional costs due to increased scope and complexity of our business;
- potential disruption of our ongoing business; and
- assumptions made on estimated development by the operator may not be accurate or may change.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties we currently own or that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as effectively as with acquisitions within our current footprint and expertise. We may not be successful in addressing these risks or any other problems encountered in connection with any acquisition we may make.

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 partially dependent upon the success of future development programs on our properties. Drilling for oil and natural gas and extracting NGLs and re-working existing wells involve numerous risks. 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;
- well blowouts and other releases of hazardous materials;
- inability to obtain or maintain leases on economic terms, where applicable;

- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services, and tubulars;
- 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 and production techniques, such as Horizontal Drilling or CO_2 injection, do not guarantee that we will find and produce oil and/or natural gas in economic quantities. Our future drilling, completion and production 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 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 ensure that these projects can be successfully developed or that wells will, if drilled, encounter reservoirs of commercially productive oil or natural gas.

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

There are numerous uncertainties inherent in estimating 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 oil and natural gas that cannot always be measured in an exact manner. Estimates of economically recoverable 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 oil and natural gas product prices, future operating costs, severance and excise taxes, development costs, workover 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 and different engineers preparing reserves estimates.

Accordingly, reserve estimates may be subject to downward or upward adjustments. 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 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 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 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 oil and natural gas properties when 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 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.

We are required under the terms of our Senior Secured Credit Facility to hedge a certain portion of our anticipated oil and natural gas production for future periods. We may also elect to hedge additional production volumes from time to time based upon our view of the attractiveness of commodity futures and the risks that downward price fluctuations might pose to our business plans. When we engage in hedging transactions, we typically utilize costless collars or fixed price swaps to cost-effectively provide us with some protection against price changes. We have not historically 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 future derivative instruments. Derivative arrangements may also expose us to the risk of financial loss in some circumstances, including, but not limited to, if:

- actual 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, in a rising commodity price environment, derivative arrangements will limit the extent to which we might benefit from increases in prices of oil and natural gas and may expose us to cash margin requirements.

Our operations may require significant amounts of capital and additional financing may be necessary in order for us to continue our exploitation activities.

Cash flow from our production 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 oil and natural gas acquisitions, exploitation, and development activities. If our revenues decrease as a result of decreases in production, 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 be available to us on favorable terms.

Government regulation and liability for oil and natural gas operations and environmental matters may adversely affect our business and results of operations.

Oil and natural gas operations are subject to extensive federal, state, and local government regulations, which may change 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 oil and natural gas from wells below actual production capacity in order to conserve supplies of 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 oil and natural gas, by-products thereof, the emission of CO_2 or other greenhouse gases, and other substances and materials released, produced or used in connection with oil and natural gas operations. These laws and regulations may affect the costs, manner, and feasibility of our operations by, among other things, requiring us to make significant expenditures in order to comply and restricting the areas available for oil and gas production. Failure to comply with these laws and regulations may result in substantial liabilities to third-parties or governmental entities. In addition, we may be liable for significant environmental damages and cleanup costs, without regard to fault, for releases of hazardous materials on or from property we own or operate, even if we did not cause or contribute to the release. 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 by imposing new emission controls, penalties, fines and/or fees, taxes and tariffs on carbon that could have the effect of raising prices to the end user and thereby reducing the demand for our products.

The risks arising out of the threat of climate change, including transition risks and physical risks, may adversely affect our business and results of operations.

The threat of climate change poses both transition risks and physical risks that could have a material adverse effect on us. Transition risks may arise from political and regulatory, legal, technological or financial changes as society tries to safeguard the climate, while physical risks may result from extreme weather events or other shifts in the natural world.

We have been facing increased political and regulatory risks as federal, state and local governments have adopted new measures to restrict sources of greenhouse gas emissions and promote energy alternatives. Many such measures have been proposed, and still more can be expected. From time to time, there are proposals to ban Hydraulic Fracturing of oil and natural gas wells and to remove more lands, both onshore and offshore, from new hydrocarbon production. Many other actions could be pursued such as more rigorous requirements for drilling and construction permits, stricter greenhouse gas emissions standards for both new and existing sources, further limits on construction of new pipelines, reinstatement of the ban on oil exports, enhanced reporting obligations, taxing carbon emissions and creating further incentives for use of alternative energy sources. These actions may cause operational delays or restrictions, increased operating costs and additional regulatory burdens.

Litigation risks are also increasing for oil and natural gas companies. A number of suits alleging, among other things, that oil and natural gas companies created public nuisances by producing fuels that contributed to climate change have been brought in state or federal court.

Technological changes may drive market demand for products other than oil and natural gas. Wider adoption of hybrid engines and electric cars, for example, would reduce demand for our products. At the same time, our capital and operating costs may increase if we need to add new emission reduction technologies.

There are also financial risks for the petroleum industry. It may become more difficult for us to access the capital markets if the threat of climate change discourages new investment. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect not to provide funding for fossil fuel energy companies. Limitation of investments in and financings for the energy industry could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The threat of climate change also may subject our operations and business to severe weather or other natural hazards, such as flooding, drought, wildfires, and extreme temperatures. Any such event could halt production or exploration activities, disrupt transportation and reduce consumer demand.

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, volatile oil and natural gas prices, geopolitical issues, the availability and cost of credit, the United States mortgage market, uncertainties with regard to European sovereign debt, the slowdown in economic growth in large emerging and developing markets, such as China, regional or worldwide increases in tariffs or other trade restrictions, and other issues have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on domestic and international financial markets and commodity prices. If uncertain or poor economic, business, or industry conditions in the United States or abroad remain prolonged, demand for petroleum products could diminish or stagnate, 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.

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 ("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 our financial condition. In December 2019, COVID-19 was identified in Wuhan, China and rapidly spread around the world. This virus and its variants, and governmental actions to contain it, continue to have a material impact globally. 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, governmental restrictions intended to contain COVID-19 or future pandemics have in the past, and may in the future, significantly impact economic activity and markets and dramatically reduce actual or anticipated demand for oil and natural gas, adversely impacting the prices we receive for our production. The severity and duration of any such events are uncertain and difficult to predict, as is the extent that such events may have on our business.

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 natural 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 natural gas distribution systems in the United States and abroad. Computers are necessary to transport our oil and natural gas production to market. A cyber-attack directed at oil and natural 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 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 oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of oil, natural gas, or well fluids, fires, formations with abnormal pressures, hurricanes and storms, flooding, pollution, releases of toxic gas, and other environmental hazards and risks, which can result in (1) damage to or destruction of wells and/or production facilities, (2) damage to or destruction of formations, (3) injury to persons, (4) loss of life, or (5) 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. Should we experience any losses, the costs of our premiums may rise, which could in turn reduce the amount of insurance we are able to carry.

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 our executive officers to source, evaluate, and close deals, raise capital, and oversee our development activities and operations. Presently, we are not a beneficiary of any key man life insurance.

Oilfield 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 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 natural 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 providing services for any reason or we may not be able to source the services or 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 may assume risks and financial responsibility for drilling and completing wells on our Williston Basin properties if our operating partner declines to drill wells and it or other joint interest owners elect not to participate.

As discussed elsewhere in this report, pursuant to agreements related to our interests in the Williston Basin properties, we have the ability to propose to the operator a drilling plan for certain wells, which the operator may accept or reject. In the event the operator rejects our proposed drilling plan, we have the right to undertake all necessary activities to drill and complete the wells and related facilities in accordance with our proposed drilling plan. In the event we undertake to do so, and the operator and other joint interest owners elect not to participate, we will bear the entire liability and expense associated with drilling and completing the wells and related facilities, subject only to our right to recoup costs incurred on behalf of non-participating joint interest owners to the extent a well generates sufficient revenues to do so. Ongoing operations of any wells we elect to drill, will be turned over to the operator of the property upon completion. If we elect to proceed to drill and complete wells we have proposed and the operator has rejected, certain of the risks highlighted elsewhere in this report, including, without limitation, the risks associated with drilling oil and natural gas wells and in addition to bearing the liability and costs associated with any wells we elect to drill and complete, many of the risks highlighted elsewhere herein will be exacerbated, including, without limitation, the risks of developing economic reserves; the risks associated with the drilling and completion of oil and natural gas wells, including potential environmental and other operating liabilities, inadequate insurance to cover the expenses and liabilities associated with such risks, price increases and delivery delays for required drilling and completion equipment, products and services; and financing risks, as we may be required to bear a share of such expenses to an extent that is disproportionate to our economic interest in the property.

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

The marketability of the oil and natural gas that we produce depends upon the proximity of our reserves and production to, and the capacity of, facilities and third-party services, including 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 natural gas companies.

Our competitors include major integrated oil and natural gas companies, numerous larger independent 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 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 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, natural gas, and mineral production depends on good title to our property.

Good and clear title to our oil, natural gas, and mineral properties is important to our business. Although title reviews will generally be conducted prior to the purchase of most oil, natural 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.

Unanticipated changes in effective tax rates or laws or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.

We are subject to tax by U.S. federal, state, and local tax authorities. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of our deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- tax effects of stock-based compensation;
- costs related to intercompany restructurings; or
- changes in tax laws, regulations, or interpretations thereof.

For example, in previous years, legislation has been proposed to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and natural gas exploration and production companies. Such proposed changes have included: (1) a repeal of the percentage depletion allowance for oil and natural gas properties; (2) the elimination of deductions for intangible drilling and exploration and development costs; (3) the elimination of the deduction for certain production activities; and (4) an extension of the amortization period for certain geological and geophysical expenditures. With President Biden taking office in 2021 and the shift in the control of Congress, there is an increased risk of the enactment of legislation that alters, eliminates, or defers these or other tax deductions utilized within the industry, which could adversely affect our business, financial condition, results of operations, and cash flows.

In addition, we may be subject to audits of its income, sales, and other transaction taxes by U.S. federal, state, and local taxing authorities. Outcomes from these audits could have an adverse effect on our financial condition and results of operations.

Risks Associated with our Common Stock

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

Our common stock has a relatively low trading volume and the market price has been, and is likely to continue to be, volatile. The variance in our stock price makes it difficult to forecast 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;
- changes or fluctuations in the commodity prices of oil and natural gas;
- general conditions and trends in the 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, 2022, our executive officers and directors, in the aggregate, beneficially owned approximately 2,554,184 million shares, or approximately 7.6% of our outstanding common stock and, based on recent filings with the SEC, we believe two large unaffiliated fund complexes each owned in excess of 6% of the outstanding shares of our common stock. As a result, a significant percentage of our common stock is concentrated in the hands of relatively few shareholders. These shareholders 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 any matter that requires shareholder approval, including 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. Trading volume in our common stock is relatively low compared to larger companies. 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, only two research analysts actively cover our company. The limited number of published reports by 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.

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 our 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.

There may be future sales or issuances of our common stock, which will dilute the ownership interests of stockholders and may adversely affect the market price of our common stock.

We may in the future issue additional shares of common stock, including securities that are convertible into or exchangeable for, or that represent the right to receive, common stock or substantially similar securities, which may result in dilution to our stockholders. In addition, our stockholders may be further diluted by future issuances under our equity incentive plans. The market price of our common stock could decline as a result of sales or issuances of a large number of shares of our common stock or similar securities in the market after this offering or the perception that such sales or issuances could occur.

Non-U.S. holders may be subject to U.S. income tax and withholding tax with respect to gain on disposition of the Company's common stock.

We believe we are a U.S. real property holding corporation. As a result, Non-U.S. holders that own (or are treated as owning under constructive ownership rules) more than a specified amount of our common stock during a specified time period may be subject to U.S. federal income tax and withholding on a sale, exchange or other disposition of such common stock, and may be required to file a U.S. federal income tax return.

Investor sentiment towards climate change, fossil fuels, sustainability, and other ESG matters could adversely affect our business and our stock price.

There have been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities, and other groups, to promote the divestment of shares of fossil fuel companies, as well as to pressure lenders and other financial services companies to limit or curtail activities with fossil fuel companies. As a result, some financial intermediaries, investors, and other capital markets participants have reduced or ceased lending to, or investing in, companies that operate in industries with higher perceived environmental exposure, such as the oil and natural gas industry. For example, in December 2020, the State of New York announced that it will be divesting the state's Common Retirement Fund from fossil fuels. If this or similar divestment efforts are continued, the price of our common stock or debt securities, and our ability to access capital markets or to otherwise obtain new investment or financing, may be negatively impacted.

Members of the investment community are also increasing their focus on ESG practices and disclosures, including practices and disclosures related to greenhouse gases and climate change in the energy industry in particular, and diversity and inclusion initiatives and governance standards among companies more generally. As a result, we may face increasing pressure regarding our ESG practices and disclosures. Additionally, members of the investment community may screen companies such as ours for ESG performance before investing in our common stock or debt securities or lending to us. Over the past few years there has also been an acceleration in investor demand for ESG investing opportunities, and many large institutional investors have committed to increasing the percentage of their portfolios that are allocated towards ESG-focused investments. As a result, there has been a proliferation of ESG-focused investment funds seeking ESG-oriented investment products.

If we are unable to meet the ESG standards or investment or lending criteria set by these investors and funds, we may lose investors, investors may allocate a portion of their capital away from us, our cost of capital may increase, the price of our common stock may be negatively impacted, and our reputation may also be negatively affected.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in Item 1. *Business* above and in Note 5, *"Property and Equipment"* to our consolidated financial statements in Item 8. *Consolidated Financial Statements and Supplementary Data*, which information is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 11, *"Commitments and Contingencies"* to our consolidated financial statements in Item 8. *Consolidated Financial Statements and Supplementary Data* 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 stock exchange under the ticker symbol "EPM".

Shares Outstanding and Holders

As of June 30, 2022, there were 33,470,710 shares of common stock issued and outstanding. As of September 1, 2022, there were approximately 219 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, we made the following cash dividends per share:

	Fiscal Year	
	2022	**2021**
Fourth quarter ended June 30,	$ 0.100	$ 0.050
Third quarter ended March 31,	$ 0.100	$ 0.030
Second quarter ended December 31,	$ 0.075	$ 0.025
First quarter ended September 30,	$ 0.075	$ 0.025

As of June 30, 2022, we have paid 35 consecutive quarterly dividends on our common stock. In September 2022, the Company declared a $0.12 per share dividend payable on September 30, 2022. 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.

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	50,062 (1)	—	
Total	50,062	—	1,804,275
Equity compensation plans not approved by security holders	—	—	—
Total	50,062	$ —	1,804,275

(1) In December 2016, we adopted the Equity Incentive Plan (the "2016 Plan"), which authorized the issuance of 1.1 million shares of common stock. On December 9, 2020, an amendment to the 2016 Plan was approved by our stockholders that increased the number of shares available for issuance by 2.5 million shares to a maximum of 3.6 million shares. As of June 30, 2022, we have granted 1.8 million equity awards under the 2016 Plan and 1.8 million shares of common stock remain available for future grants.

Issuer Purchases of Equity Securities

During the fourth quarter ended June 30, 2022, we 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 our employees to pay their share of payroll taxes arising from vesting of restricted stock.

Item 6. Reserved

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

Executive Overview

General

Evolution Petroleum Corporation is an independent energy company focused on maximizing total returns to its shareholders through the ownership of and investment in onshore oil and natural gas properties in the United States. In support of that objective, our long-term goal is to maximize total shareholder return from a diversified portfolio of long-life oil and natural gas properties built through acquisitions and through selective development opportunities, production enhancements, and other exploitation efforts on our oil and natural gas properties.

Our oil and natural gas properties consist of non-operated interests in the Delhi Holt-Bryant Unit in the Delhi Field in Northeast Louisiana, a CO_2 enhanced oil recovery ("EOR") project; non-operated interests in the Hamilton Dome Field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir; non-operated interests in the Barnett Shale located in North Texas, a natural gas producing property; non-operated interests in the Williston Basin in North Dakota, a producing oil and natural gas property; non-operated interests in the Jonah Field in Sublette County, Wyoming, a natural gas producing field; and small overriding royalty interests in four onshore central Texas wells.

Our non-operated interests in the Delhi Field, a CO_2-EOR project, consist of approximately 24% average net working interest, with an associated 19% revenue interest and separate overriding royalty and mineral interests of approximately 7% yielding a total average net revenue interest of approximately 26%. The field is operated by Denbury Onshore LLC ("Denbury"). The Delhi Field is located in northeast Louisiana in Franklin, Madison, and Richland Parishes and encompasses approximately 14,000 gross unitized acres, or approximately 3,200 net acres.

Our non-operated interests in the Hamilton Dome Field, a secondary recovery field utilizing water injection wells to pressurize the reservoir, consists of approximately 24% average net working interest, with an associated 20% average net revenue interest (inclusive of a small overriding royalty interest). The approximately 5,900 gross acre unitized field, of which we hold approximately 1,400 net acres, is operated by Merit Energy Company ("Merit"), who owns the vast majority of the remaining working interest in the Hamilton Dome Field. The Hamilton Dome Field is located in the southwest region of the Big Horn Basin in northwest Wyoming.

Our non-operated interests in the Barnett Shale, a natural gas producing shale reservoir, consists of approximately 17% average net working interest with an associated 14% average net revenue interest (inclusive of small overriding royalty interests). The approximately 21,000 net acres are held by production across nine North Texas counties. The oil and natural gas properties are primarily operated by Diversified Energy Company with approximately 10% of wells operated by seven other operators.

On January 14, 2022, we acquired non-operated working interests in 73 producing wells in the Williston Basin with an average net working interest of approximately 39% and average net revenue interest of approximately 33% located on approximately 45,000 net acres (approximately 90% held by production) across Billings, Golden Valley, and McKenzie Counties in North Dakota (the "Williston Basin Acquisition"). After taking into account customary closing adjustments and an effective date of June 1, 2021, cash consideration was $25.2 million which includes $0.3 million of transaction costs related to the acquisition. The properties are operated by Foundation Energy Management ("Foundation"), an established operator in the geographic region.

On April 1, 2022, we acquired non-operated working interests in the Jonah Field in Sublette County, Wyoming (the "Jonah Field Acquisition"). After taking into account the deposit on the acquisition, customary closing adjustments and an effective date of February 1, 2022, cash consideration at closing was $26.4 million (including $0.2 million of transaction costs). The acquired properties include an average net working interest of approximately 20% and an average net revenue interest of approximately 15% in 595 producing wells and 950 net acres. The properties are operated by Jonah ("Jonah"), an established operator in the geographic region.

Recent Developments

Dividend Declaration and Share Repurchase Program

On September 12, 2022, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2022. This represents a 20% increase over the $0.10 per common share dividend paid in the fourth quarter of fiscal year 2022. Also, on September 8, 2022, the Board of Directors authorized a share repurchase program, under which we are approved to repurchase up to $25 million of our common stock through December 31, 2024. We intend to fund repurchases from available working capital and cash provided by operating activities. As we continue to focus on our goal of maximizing total shareholder return, the Board of Directors along with the management team believe that a share repurchase program is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will depend on a variety of factors, including management's assessment of the intrinsic value of our shares, the market price of our common stock, general market and economic conditions, and applicable legal requirements. The value of shares authorized for repurchase by our Board of Directors does not require us to repurchase such shares or guarantee that such shares will be repurchased, and the program may be suspended, modified, or discontinued at any time without prior notice.

Highlights for our Fiscal Year 2022 and Operations Update

- Generated revenue of $108.9 million and net income of $32.6 million.
- Production averaged 5,953 net BOEPD.
- Returned to shareholders $11.8 million in cash dividends. We have paid out to shareholders more than $86.3 million in cash dividends since inception of the dividend program in December 2013.
- Funded all operations, development capital expenditures, and dividends out of operating cash flow.
- Closed the Jonah Field Acquisition on April 1, 2022 and the Williston Basin Acquisition on January 14, 2022, which included total proved reserves of 7.1 MMBOE and 6.1 MMBOE, respectively, as of June 30, 2022 as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") an independent reservoir engineering firm.
- Increased proved reserves 55% since prior year-end primarily due to the acquisitions of the Jonah Field properties in April 2022 and Williston Basin properties in January 2022.
- Maintained a strong financial position with low leverage.

Proved Reserves

Proved oil equivalent reserves as of June 30, 2022 were 36.2 MMBOE, a 55% increase from the previous year primarily due to the acquisitions of properties in the Williston Basin and Jonah Field in January 2022 and April 2022, respectively. The Standardized Measure for proved reserves increased 259% to $314.8 million, primarily due to the acquisitions of properties in the Williston Basin and Jonah Field and an increase in the SEC mandated trailing 12-month average first day of the month prices for oil and natural gas. Prices increased from $49.72 per barrel of oil, $2.46 per MMBtu of natural gas and $19.81 per barrel of NGLs at June 30, 2021 to $85.82 per barrel of oil, $5.19 per MMBtu of natural gas and $44.24 per barrel of NGLs at June 30, 2022. Our proved reserves consist of 32% oil, 49% natural gas, and 19% NGLs; 90% are classified as proved developed producing and 10% are proved undeveloped.

The following table is a summary of our proved reserves as of June 30, 2022 and 2021:

	Proved Reserves		
	2022	2021	Change
Reserves MMBOE	36.2	23.4	55 %
% Developed	90 %	92 %	(2)%
Liquids %	51 %	65 %	(14)%
Standardized Measure ($MM)	$ 314.8	$ 87.6	259 %

Additional property and project information is included under Item 1. *Business* and in Note 5, *"Property and Equipment"* and our *Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data*, and in Exhibit 99.1 and 99.2 of this Form 10-K.

At June 30, 2022, we had total net proved reserves of 36.2 MMBOE, a 12.8 MMBOE increase from the previous year of 23.4 MMBOE. The net increase in total proved reserves was the result of acquisitions of 9.3 MMBOE, additions and extensions of 3.6 MMBOE and net positive revisions of 2.1 MMBOE, partially offset by production of 2.2 MMBOE. Net positive revisions of 2.1 MMBOE increased primarily due to improvement in SEC trailing 12-month pricing partially offset by the removal of 1.8 MMBOE of PUDs related to Test Site V and 0.7 MMBOE of PDP at our Delhi Field property.

Impact of the COVID-19 Pandemic and Geopolitical factors

The global economy has been deeply impacted by the effects of the novel coronavirus ("COVID-19") pandemic and related efforts to mitigate the spread of the disease. These events led to crude oil prices falling to historic lows during the second quarter of 2020 and remaining depressed through much of 2020.

In 2021, the demand for oil and natural gas began to recover primarily as a result of the roll-out of the COVID-19 vaccine and lessening of pandemic related government restrictions on individuals and businesses. In addition, the recent special military operation of Russia into Ukraine and the subsequent sanctions imposed on Russia and other actions have created significant market uncertainties, including uncertainties around potential supply disruptions for oil and natural gas, which has further enhanced volatility in global commodity prices in the first half of 2022. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that these market conditions will persist.

Currently, none of our oil and natural gas properties are operated by us. As a result, in the past we have had limited ability to influence or control the operation or future development of such properties. Despite these uncertainties, we remain focused on our long-term objectives and continue to be proactive with our third-party operators to review capital expenditures and alter plans as appropriate to increase shareholder value.

Liquidity and Capital Resources

As of June 30, 2022, we had $8.3 million in cash and cash equivalents compared to $5.3 million at June 30, 2021. Our primary sources of liquidity and capital resources during the year ended June 30, 2022 were cash provided by operations as well as net borrowings under our Senior Secured Credit Facility. Our primary uses of liquidity and capital resources for the year ended June 30, 2022 were acquisitions of oil and natural gas properties and cash dividend payments to our common stockholders. As of June 30, 2022, working capital was $6.1 million, a decrease of $5.4 million from working capital of $11.5 million as of June 30, 2021.

The Senior Secured Credit Facility has a maximum capacity of $50.0 million subject to a borrowing base determined by the lender based on the value of our oil and natural gas properties. The Senior Secured Credit Facility has a current borrowing base of $50.0 million, with $21.3 million drawn as of June 30, 2022. Since year-end, we have paid down another $9.0 million under our Senior Secured Credit Facility and as of August 31, 2022, we have $12.3 million outstanding. The Senior Secured Credit Facility is secured by substantially all of our reserves associated with our oil and natural gas properties and matures on April 9, 2024.

Any future borrowings bear interest, at our option, at either the London Interbank Offered Rate ("LIBOR") plus 2.75% or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.0%. The Senior Secured Credit Facility contains covenants requiring the maintenance of (i) a total leverage ratio of not more than 3.00 to 1.00, (ii) a current ratio of not less than 1.00 to 1.00, and (iii) a consolidated tangible net worth of not less than $40.0 million, each as defined in the Senior Secured Credit Facility. It also contains other customary affirmative and negative covenants and events of default. As of June 30, 2022, we were in compliance with all covenants under the Senior Secured Credit Facility.

We are currently working on our annual redetermination with MidFirst Bank. We expect that our borrowing base will remain at $50.0 million and the Margined Collateral Value, as defined in the Ninth Amendment to the Senior Secured Credit Facility, will be set at $125.0 million. We are required to enter into hedges on a rolling 12-month basis when the borrowings under the Senior Secured Credit Facility exceed 25% of the Margined Collateral Value. Based on the current amount outstanding, the utilization percentage under the required hedging covenant is below the minimum utilization threshold of 25% and as a result we are not required to enter into additional hedges at this time. At each redetermination, our Margined Collateral Value takes into account the estimated value of our oil and natural gas properties, proved developed reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria.

On February 7, 2022, we entered into the Ninth Amendment to the Senior Secured Credit Facility. This amendment, among other things, modified the definition of utilization percentage related to the required hedging covenant such that for the purposes of determining the amount of future production to hedge, the utilization of the Senior Secured Credit Facility will be based on the Margined Collateral Value, as defined in the agreement, to the extent it exceeds the borrowing base then in effect. This amendment also required us to enter into hedges for the next 12-month period ending February 2023, covering 25% of expected oil and natural gas production over that period.

On November 9, 2021, we entered into the Eighth Amendment to the Senior Secured Credit Facility. This amendment, among other things, increased the borrowing base to $50.0 million and added a hedging covenant whereby we must hedge a certain amount of our future production on a rolling 12-month basis when 25% or more of the borrowing base is utilized. The hedging covenant was amended in the Ninth Amendment, as discussed above.

On August 5, 2021, we entered into the Seventh Amendment of our Senior Secured Credit Facility which, among other things, added definitions for the terms "Acquired Entity or Mineral Interests" and "Acquired Entity or Mineral Interests EBITDA Adjustment." Additionally, the consolidated tangible net worth covenant level was reduced to $40.0 million from $50.0 million.

We have historically funded operations through cash from operations and working capital. The primary source of cash is the sale of produced crude oil, natural gas, and NGLs. A portion of these cash flows is used to fund capital expenditures and pay cash dividends to shareholders. We expect to manage near-future development activities for our properties with cash flows from operating activities and existing working capital.

We are pursuing new growth opportunities through acquisitions and other transactions. In addition to cash on hand, we have access to the undrawn portion of the borrowing base available under our Senior Secured Credit Facility. We also have an effective shelf registration statement with the SEC under which we may issue up to $500.0 million of new debt or equity securities.

The Board of Directors instituted a cash dividend on common stock in December 2013. We have since paid 35 consecutive quarterly dividends. Distribution of a substantial portion of free cash flow in excess of operating and capital requirements through cash dividends remains a priority of our financial strategy, and it is our long-term goal to increase dividends over time, as appropriate. During the industry downturn primarily due to COVID-19, effective in the quarter ended June 30, 2020, the Board of Directors adjusted the quarterly dividend rate from $0.10 per share to $0.025 per share. The reduction in the dividend rate at that time allowed us to conserve cash for additional financial flexibility while continuing to reward shareholders with a yield of approximately 3% at the then current stock price levels. In light of our improving financial performance and industry outlook, the Board of Directors has since increased the dividend rate, with the most recent increase occurring on September 12, 2022, when the Board of Directors declared a dividend of $0.12 per share payable on September 30, 2022.

Also, on September 8, 2022, our Board of Directors authorized a share repurchase program, under which we are approved to repurchase up to $25 million of our common stock through December 31, 2024. We intend to fund any repurchases from working capital and cash provided by operating activities. As we continue to focus on our goal of maximizing total shareholder return, the Board of Directors along with the management team believe that a share repurchase program is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return. Refer to Note 15, "*Subsequent Events,"* for a further discussion of our share repurchase program.

Capital Expenditures

For the year ended June 30, 2022, we incurred $2.6 million on development capital expenditures, $26.4 million for the Jonah Field Acquisition (net of customary purchase price adjustments, excluding $3.0 million in non-cash asset retirement obligations), and $25.2 million for the Williston Basin Acquisition (net of customary purchase price adjustments, excluding $2.4 million in non-cash asset retirement obligations) and less than $0.1 million at the Delhi Field and Hamilton Dome Field, for plugging and abandoning costs.

Based on discussions with our operators, we expect capital workover projects to continue in all the fields. At Delhi Field, we anticipate capital costs for a NGL plant heat exchanger project which is currently underway. Overall, for fiscal year 2023, we expect budgeted capital expenditures to be in the range of $6.5 million to $9.5 million, which excludes any potential acquisitions. Our expected capital expenditures for the next 12 months include Foundation, the operator of our Williston Basin properties, drilling two sidetrack locations targeting the Birdbear formation. Our fiscal year 2023 budget does not include any capital expenditures for drilling at our Pronghorn and Three Forks locations.

As of June 30, 2022, our PUD reserves included 3.6 MMBOE of reserves and approximately $61.7 million of future development costs associated with the Williston Basin properties.

Funding for our anticipated capital expenditures over the near-term is expected to be met from cash flows from operations and current working capital, as well as borrowings under our Senior Secured Credit Facility as needed for future acquisitions or development of PUD reserves at our Pronghorn and Three Forks locations.

Full Cost Pool Ceiling Test

As of June 30, 2022, our capitalized costs of oil and natural gas properties were below the full cost valuation ceiling; however, we could experience an impairment if commodity price levels were to substantially decline. Lower commodity prices would reduce the excess, or cushion, of our valuation ceiling over our capitalized costs and may adversely impact our ceiling tests in future quarters. We cannot give assurance that a write-down of capitalized oil and natural gas properties will not be required in the future. Under the full cost method of accounting, capitalized costs of oil and natural gas properties, net of accumulated depletion, depreciation, and amortization and related deferred taxes, are limited to the estimated future net cash flows from proved oil and natural 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 natural 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 as of June 30, 2022 were $85.82 per barrel of oil, $5.19 per MMBtu of natural gas and $44.24 per barrel of NGLs. At December 31, 2020 and September 30, 2020, we recorded ceiling test impairment charges of $15.2 million and $9.6 million, respectively. The ceiling test impairments were driven by decreases in the first-day-of-the-month average price for oil used in the ceiling test calculation. At June 30, 2022, a 10% decrease in commodity prices used to determine our proved reserves would not have resulted in an impairment of our oil and natural gas properties.

	Twelve-Month Period Ended:				
	6/30/2021	9/30/2021	12/31/2021	3/31/2022	6/30/2022
Crude Oil	$ 49.72	$ 57.64	$ 66.55	$ 75.28	$ 85.82
Natural Gas	$ 2.46	$ 2.97	$ 3.64	$ 4.15	$ 5.19

Overview of Cash Flow Activities

	Years Ended June 30,		
	2022	2021	Change
Cash flows provided by operating activities	$ 52,460	$ 4,733	$ 47,727
Cash flows used in investing activities	(54,873)	(18,769)	(36,104)
Cash flows provided by (used in) financing activities	5,416	(349)	5,765
Net increase (decrease) in cash and cash equivalents	$ 3,003	$ (14,385)	$ 17,388

Cash provided by operating activities increased $47.7 million during the fiscal year ended June 30, 2022 compared to fiscal year ended June 30, 2021 primarily due to an increased average daily production and an approximate $13.26 per BOE average realized price increase which both contributed to higher revenues in fiscal year 2022.

Cash used in investing activities increased $36.1 million primarily due to the acquisition of the Jonah Field properties in April 2022 totaling $26.4 million (net of customary purchase price adjustments) and Williston Basin properties in January 2022 totaling $25.8 million (net of customary purchase price adjustments), compared to the acquisition of the Barnett Shale properties in May 2021 for $18.3 million (net of customary purchase price adjustments). In addition, capital expenditures increased $1.0 million in fiscal year 2022 due to increased capital workovers for certain return-to-production projects now viable with the increase in commodity prices.

Net cash flows provided by financing activities were $5.4 million for the year ended June 30, 2022, compared to $0.3 million of net cash flows used in financing activities for the year ended June 30, 2021. As of June 30, 2021, we had borrowings of $4.0 million outstanding under our Senior Secured Credit Facility. During the year ended June 30, 2022, we increased these borrowings by a net $17.3 million, ending the year with $21.3 million outstanding under the Senior Secured Credit Facility. In fiscal year 2022, we used cash of $11.8 million for dividends paid to our common stockholders compared to $4.3 million in fiscal year 2021.

Results of Operations

Years Ended June 30, 2022 and 2021

We reported net income of $32.6 million for the year ended June 30, 2022 compared to a net loss of $16.4 million for the year ended June 30, 2021. The following table summarizes the comparison of financial information for the periods presented:

(in thousands, except per unit and per BOE amounts)	Years Ended June 30, 2022	2021	Variance	Variance %
Net income (loss)	$ 32,628	$ (16,438)	$ 49,066	(298.5) %
Revenues:				
Crude oil	52,683	26,411	26,272	99.5 %
Natural gas	39,174	2,629	36,545	1,390.1 %
Natural gas liquids	17,069	3,662	13,407	366.1 %
Total Revenue	108,926	32,702	76,224	233.1 %
Operating costs:				
Lease operating costs:				
CO_2 costs	7,708	3,062	4,646	151.7 %
Ad valorem and production taxes	6,960	1,280	5,680	443.8 %
Other lease operating costs	33,989	12,245	21,744	177.6 %
Depletion, depreciation, and amortization:				
Depletion of full cost proved oil and gas properties	7,518	4,903	2,615	53.3 %
Depreciation of other property and equipment	4	7	(3)	(42.9) %
Amortization of intangibles	—	47	(47)	(100.0) %
Accretion of asset retirement obligations	531	210	321	152.9 %
Impairment of proved property	—	24,792	(24,792)	(100.0) %
Impairment of Well Lift Inc. - related assets	—	146	(146)	(100.0) %
General and administrative:				
General and administrative	6,710	5,496	1,214	22.1 %
Stock-based compensation	125	1,258	(1,133)	(90.1) %
Other Income (expenses):				
Net gain (loss) on derivative contracts	(3,763)	(615)	(3,148)	511.9 %
Interest and other income	95	40	55	137.5 %
Interest expense	(572)	(103)	(469)	455.3 %
Income tax (expense) benefit	(8,513)	4,984	(13,497)	(270.8) %
Production:				
Crude oil (MBBL)	619	555	64	11.5 %
Natural gas (MMCF)	7,141	963	6,178	641.5 %
Natural gas liquids (MBBL)	364	171	193	112.9 %
Equivalent (MBOE)[(1)]	2,173	887	1,286	145.0 %
Average daily production (BOEPD)[(1)]	5,953	2,430	3,523	145.0 %
Average price per unit[(2)]:				
Crude oil (BBL)	$ 85.11	$ 47.59	$ 37.52	78.8 %
Natural gas (MCF)	5.49	2.73	2.76	101.1 %
NGL (BBL)	46.89	21.42	25.47	118.9 %
Equivalent (BOE)[(1)]	50.13	36.87	13.26	36.0 %
Average cost per unit:				
Operating costs:				
Lease operating costs:				
CO_2 costs	$ 3.55	$ 3.45	0.10	2.9 %
Ad valorem and production taxes	3.20	1.44	1.76	122.2 %
Other lease operating costs	15.64	13.80	1.84	13.3 %
Depletion of full cost proved oil and gas properties	3.46	5.53	(2.07)	(37.4) %
General and administrative:				
General and administrative	3.09	6.20	(3.11)	(50.2) %
Stock-based compensation	0.06	1.42	(1.36)	(95.8) %

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

(2) Amounts exclude the impact of cash paid or received on the settlement of derivative contracts since we did not elect to apply hedge accounting.

Revenues

Fiscal year ended June 30, 2022 revenues increased 233.1% to $108.9 million compared to $32.7 million for the fiscal year ended June 30, 2021. The increase in revenue is primarily due to a 145% increase in average daily equivalent production from 2,430 BOEPD to 5,953 BOEPD due the addition of the Jonah Field Acquisition in April 2022, Williston Basin Acquisition in January 2022, and Barnett Shale Acquisition in May 2021, which increased current fiscal year production by approximately 518 BOEPD, 241 BOEPD, and 2,847 BOEPD, respectively. In addition, our average realized commodity prices (excluding the impact of derivative contracts) increased approximately $13.26 per BOE, or 36%, for the fiscal year ended June 30, 2022 compared to June 30, 2021. Oil and natural gas prices are inherently volatile and began to stabilize in 2021 and continuing into 2022. Our average realized oil price was higher primarily due to the recovery of WTI pricing in 2022, as the demand for oil has begun to recover primarily as a result of the roll-out of the COVID -19 vaccines, lessening of pandemic related government restrictions on individuals and businesses, and sanctions affecting Russian oil and natural gas supplies.

Lease Operating Costs

The following table summarizes CO_2 costs per Mcf and CO_2 volumes for the years ended June 30, 2022 and 2021. CO_2 purchase costs are for the Delhi Field. Under our contract with the Delhi Field 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,			
	2022	2021	Variance	Variance %
CO_2 costs per MCF	$ 1.07	$ 0.71	$ 0.36	50.7 %
CO_2 volumes (MMCF per day, gross)	82.6	49.1	33.5	68.2 %

The $4.6 million increase in CO_2 costs for the fiscal year ended June 30, 2022 was primarily due to a 68.2% increase in purchased CO_2 volumes combined with a 50.7% increase in CO_2 costs per MCF, which was driven by a 78.8% increase in our average realized oil price. The increase in purchased CO_2 volumes is due to the completion of preventative maintenance on the pipeline that supplies newly purchased CO_2 to the Delhi Field which resulted in temporary suspension of CO_2 purchases for the three months ended September 30, 2021. Additionally, CO_2 purchase nominations increased throughout fiscal year 2022 to compensate for reduced reservoir pressure. CO_2 purchases provide approximately 20% of the injected volumes in the field and the field’s recycle facilities provide the other 80%. The pipeline is owned and operated by Denbury and we do not have any ownership in the pipeline. On a per unit basis, CO_2 costs were $3.55 per BOE and $3.45 per BOE for the years ended June 30, 2022 and 2021, respectively.

Ad valorem and production taxes were $7.0 million and $1.3 million for the years ended June 30, 2022 and 2021, respectively. On a per unit basis, ad valorem and production taxes were $3.20 per BOE and $1.44 per BOE for the years ended June 30, 2022 and 2021, respectively. The increase in ad valorem and production taxes is primarily due to increases in oil and natural gas prices and increased production volumes described above as production taxes are based on sales at the wellhead.

Compared to fiscal year ended June 30, 2021, other lease operating costs increased 177.6% primarily due to the Jonah Field Acquisition in April 2022, Williston Basin Acquisition in January 2022 and Barnett Shale Acquisition in May 2021. Other lease operating costs per BOE for our Jonah Field, Williston Basin and Barnett Shale properties were approximately $10.69 per BOE, $21.86 per BOE and $14.70 per BOE, respectively, for the years ended June 30, 2022. Other lease operating costs for the Delhi and Hamilton Dome fields increased $0.8 million and $0.9 million, respectively, due to higher labor, electricity and chemical expenses during the year ended June 30, 2022.

Depletion expense increased $2.6 million or 53.3% from $4.9 million for the fiscal year ended June 30, 2021 to $7.5 million for the fiscal year ended June 30, 2022 primarily due to an increase in production. On a per unit basis, depletion expense was $3.46 per BOE and $5.53 per BOE for the fiscal years ended June 30, 2022 and 2021, respectively. The integration of the Jonah Field properties in April 2022, Williston Basin properties in January 2022, and Barnett Shale properties in May 2021 together with the ceiling test impairments recorded during the fiscal year ended June 30, 2021 contributed to the overall lower composite depletion per BOE rate for the year ended June 30, 2022.

Impairment of Proved Property

We utilize the full cost method of accounting for our oil and natural gas properties under the full cost method of accounting, capitalized costs of oil and natural gas properties, net of accumulated depletion, depreciation, and amortization and related deferred taxes, are limited to the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties included in the amortization base, plus the cost of unproved properties excluded from amortization, as adjusted for related income tax effects (the valuation "ceiling"). As of June 30, 2022, our net book value of oil and natural gas properties did not exceed the current ceiling. During the fiscal year ended June 30, 2021, we recorded a proved property impairment of $24.8 million primarily as a result of the decline in the price of oil over the historical 12-month period.

Impairment of Well Lift Inc. - Related Expenses

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 approximately 18% of the common stock and 100% of the preferred 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. We evaluate the investment for impairment when we identify any events or changes in circumstances that might have a significant adverse effect on the fair value of the investment. As of March 31, 2021, we reviewed our investment in WLI for potential impairment and, as a result, recorded an impairment expense of $0.1 million. This impairment charge was recorded based on a variety of factors including the level of activity associated with this technology.

General and Administrative Expenses

General and administrative expenses for the fiscal year ended June 30, 2022 increased $1.2 million, or 22.1%, to $6.7 million compared to $5.5 million for the fiscal year ended June 30, 2021. The increase is primarily due to approximately $0.2 million for salary and employee benefits due to additional personnel, $0.3 million in severance, $0.2 million for professional fees related to increased accounting services as a result of the Jonah Field Acquisition, the Williston Basin Acquisition and the Barnett Shale Acquisition, and $0.3 million for increased business development activity. On a per unit basis, general and administrative expenses decreased $3.11 per BOE to $3.09 per BOE for the year ended June 30, 2022 from $6.20 per BOE for the prior year. The decrease in general and administrative expenses on a per unit basis are due to the increased production volumes described above.

Stock-based Compensation Expenses

Stock-based compensation decreased $1.1 million, or 90%, to $0.1 million for the year ended June 30, 2022 compared to $1.3 million the prior period due to a $1.2 million reduction in current period expense related to the forfeiture of unvested shares in connection with severance.

Net Gain (Loss) on Derivative Contracts

Periodically, we utilize commodity derivative financial instruments to reduce our exposure to fluctuations in oil and natural gas prices. We have elected not to designate our open derivative contracts for hedge accounting, and accordingly, we recorded the net change in the mark-to-market valuation of the derivative contracts in the consolidated statements of operations. The amounts recorded on the consolidated statements of operations related to derivative contracts represent the (i) gains (losses) 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. The table below summarizes our net realized and unrealized gains (losses) on derivative contracts as well as the impact of net realized (gains) losses on our average realized prices for the periods presented. As a result of the Williston Basin Acquisition in January 2022 and Jonah Field Acquisition in April 2022, we were required by the terms of our Senior Secured Credit Facility to hedge a portion of our production. The increase in commodity prices since entering into the hedges resulted in a realized loss on hedges for the year ended June 30, 2022 and an unrealized loss due to the mark-to-market value of remaining hedges. Certain of our hedges begin to expire in October 2022 with our final hedges expiring March 2023. As of June 30, 2022, we had a $0.2 million derivative asset all of which was classified as current, and a $2.2 million derivative liability, all of which was classified as current.

(in thousands, except per unit and per BOE amounts)	Years Ended June 30, 2022	2021	Variance	Variance %
Realized gain (loss) on derivative contracts	$ (1,769)	$ (2,526)	$ 757	(30.0) %
Unrealized gain (loss) on derivative contracts	(1,994)	1,911	(3,905)	(204.3) %
Total net gain (loss) on derivative contracts	$ (3,763)	$ (615)	$ (3,148)	511.9 %
Average realized crude oil price per Bbl	$ 85.11	$ 47.59	$ 37.52	78.8 %
Cash effect of oil derivative contracts per Bbl	(1.24)	(4.55)	3.31	(72.7) %
Crude oil price per Bbl (including impact of realized derivatives)	$ 83.87	$ 43.04	$ 40.83	94.9 %
Average realized natural gas price per Mcf	$ 5.49	$ 2.73	$ 2.76	101.1 %
Cash effect of natural gas derivative contracts per Mcf	(0.14)	—	(0.14)	— %
Natural gas price per Mcf (including impact of realized derivatives)	$ 5.35	$ 2.73	$ 2.62	96.0 %

Interest Expense

Interest expense increased $0.5 million during the fiscal year ended June 30, 2022 compared to fiscal year 2021 primarily due to the increased borrowings outstanding on our Senior Secured Credit Facility due to our acquisitions throughout the year.

Income tax (expense) provision

For the year ended June 30, 2022, we recognized income tax expense of $8.5 million on net income before income taxes of $41.1 million compared to an income tax benefit of $5.0 million on net loss before income taxes of $21.4 million for the year ended June 30, 2021.

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 1, *"Summary of Significant Events and Accounting Policies"* 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 natural 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 natural gas properties is not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in 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, 2022, we had no unevaluated property costs. Oil and natural gas properties include costs that are excluded from depletion and amortization, which represent investments in unproved and unevaluated properties and include non-producing leasehold, geologic 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 geologic, 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 geologic 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, 2022 would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction our proved reserve estimates at June 30, 2022 of 10% would affect depletion, depreciation, and amortization expense by approximately $0.4 million.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and natural gas reserves. The rule allows consideration of new technologies in evaluating reserves, generally limits the designation of proved reserves to those projects forecasted 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 natural 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 natural 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. 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. The deferred tax asset and valuation allowance of $0.1 million related to the portion of the NOLs that are limited by IRC Section 382 were written off during the year ended June 30, 2022.

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. The Company has historically established a valuation allowance against net operating losses and other deferred tax assets to the extent it believes the future benefit from these assets will not be realized in the statutory carryforward periods, 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. At the time of this report, we have not recorded a valuation allowance for our expected inability to realize the future benefits of certain federal and state deferred tax assets as further discussed in Note 7, *"Income Taxes"*.

Stock-based Compensation. The fair value, and for certain awards the expected vesting period, of our performance-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 our 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 performance-based awards is based on our total common stock return compared to a peer group of other companies in our industry with comparable market capitalizations and, for certain awards, our share price attaining a set target.

Recent Accounting Pronouncements. Refer to Note 1, *"Summary of Significant Events and Accounting Policies"* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* for discussion of the recent accounting pronouncements issued by the Financial Accounting Standards Board.

Item 7A. Quantitative and Qualitative Disclosures About Market Risks

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 and natural gas prices. We do not enter into derivative contracts for speculative trading purposes.

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. For the derivative contracts settled during fiscal 2022 and 2021, we did not post collateral. 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 8, *"Derivatives"* to our consolidated financial statements for more details.

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. Additionally, any borrowings under the Senior Secured Credit Facility will bear interest, at our option, at either LIBOR plus 2.75%, subject to a minimum LIBOR of 0.25%, or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%. LIBOR rates are sensitive to the period of contract and market volatility, as well as changes in forward interest rate yields. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Item 8. Consolidated Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
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, 2022 and 2021, 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, 2022 and 2021, 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 audit 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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Depletion, Depreciation and Amortization ("DD&A") and Full Cost Ceiling Test Impairment Calculation ("Ceiling Test")

As described in Note 1, the Company follows the full cost method of accounting, pursuant to which oil and natural gas properties are amortized using the unit-of-production method over total proved reserves. The Company's proved oil and natural gas properties are evaluated for impairment by the Ceiling Test, utilizing the Company's proved oil and natural gas reserves in accordance with accounting principles generally accepted in the United States of America and SEC guidelines. For the year ended June 30, 2022, the Company recorded DD&A related to its proved oil and natural gas properties of approximately $7.5 million, and there was no ceiling test impairment.

The Company engages two independent reservoir engineering firms, to serve as a management specialist and to assist with the estimation of proved oil and natural gas reserves. To estimate the volume of proved oil and natural gas reserves and associated future net cash flows, management and their specialists make significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties ("PUDs"). The estimation of proved oil and natural gas reserves is impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required. Changes in significant assumptions or engineering data could have a significant impact on the amount of DD&A and impairment recorded for the Company's proved oil and natural gas properties.

We identified the impact of proved oil and natural gas reserves on DD&A and the Ceiling Test as a critical audit matter due to use of significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the significant assumptions used in developing those estimates of proved oil and natural gas reserves.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the knowledge, skill, and ability of the Company's third-party reservoir engineering specialists and their relationship to the Company, inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the proved reserve volumes, and reading the reserve report prepared by the reservoir engineering specialists.
- Evaluating significant assumptions used by management and its specialists in developing the estimates of proved oil and natural gas reserves, including pricing differentials, future operations costs, future production rates and capital expenditures. The procedures performed included tests of the data inputs used by specialists for completeness and accuracy and an evaluation of the specialist's findings. The procedures performed included:
  - Testing the data inputs used by specialist for completeness and accuracy;
  - Testing the specialist's findings for mathematical accuracy; and,
  - Performing analytical procedures on pricing, reserve quantities and cost estimates developed by management and its specialists. Those procedures entailed comparisons of:
    - prices to historical benchmark prices, adjusted for pricing differentials,
    - production forecasts to recent historical actual production,
    - projections of lease operating costs to costs incurred by property during fiscal year ended June 30, 2022, and
    - projected production taxes to recent historical taxes incurred and to statutory tax rates.
- Evaluating the accuracy of revenue and working interest percentages used in the reserve reports by comparing a sample of such interests to the land records.
- Performing retrospective review of historical estimates of proved oil and natural gas reserves to identify potential management bias in estimates.

Testing the accuracy of the Company's depletion and impairment calculations that included these proved reserves.

/s/ Moss Adams LLP

Houston, Texas
September 14, 2022

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

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	June 30, 2022	June 30, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 8,280	$ 5,277
Receivables from crude oil, natural gas, and natural gas liquids sales	24,080	8,687
Receivables for federal and state income tax refunds	—	3,108
Derivative contract assets	170	—
Prepaid expenses and other current assets	3,838	1,036
Total current assets	36,368	18,108
Property and equipment, net of depletion, depreciation, amortization, and impairment		
Oil and natural gas properties, net—full-cost method of accounting, of which none were excluded from amortization	110,508	58,516
Other property and equipment, net	—	11
Total property and equipment, net	110,508	58,527
Other assets, net	1,171	71
Total assets	$ 148,047	$ 76,706
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 15,133	$ 1,613
Accrued liabilities and other	11,893	4,943
Derivative contract liabilities	2,164	—
State and federal taxes payable	1,095	38
Total current liabilities	30,285	6,594
Long term liabilities		
Senior secured credit facility	21,250	4,000
Deferred income taxes	7,099	5,957
Asset retirement obligations	13,899	5,539
Operating lease liability	—	21
Total liabilities	72,533	22,111
Commitments and contingencies (Note 11)		
Stockholders' equity		
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 33,470,710 and 33,514,952 shares as of June 30, 2022 and 2021, respectively	33	34
Additional paid-in capital	42,629	42,541
Retained earnings	32,852	12,020
Total stockholders' equity	75,514	54,595
Total liabilities and stockholders' equity	$ 148,047	$ 76,706

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended June 30, 2022	Years Ended June 30, 2021
Revenues		
Crude oil	$ 52,683	$ 26,411
Natural gas	39,174	2,629
Natural gas liquids	17,069	3,662
Total revenues	108,926	32,702
Operating costs		
Lease operating costs	48,657	16,587
Depletion, depreciation, and amortization	8,053	5,167
Impairment of proved property	—	24,792
Impairment of Well Lift Inc. - related assets	—	146
General and administrative expenses	6,835	6,754
Total operating costs	63,545	53,446
Income (loss) from operations	45,381	(20,744)
Other income and expenses		
Net gain (loss) on derivative contracts	(3,763)	(615)
Interest and other income	95	40
Interest expense	(572)	(103)
Income (loss) before income taxes	41,141	(21,422)
Income tax (expense) benefit	(8,513)	4,984
Net income (loss)	$ 32,628	$ (16,438)
Earnings (loss) per common share:		
Basic	$ 0.97	$ (0.50)
Diluted	$ 0.96	$ (0.50)
Weighted average number of common shares outstanding		
Basic	32,952	32,744
Diluted	33,306	32,744

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended June 30, 2022	Years Ended June 30, 2021
Cash flows from operating activities:		
Net income (loss)	$ 32,628	$ (16,438)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, and amortization	8,053	5,167
Impairment of proved property	—	24,792
Impairment of Well Lift Inc. - related assets	—	146
Stock-based compensation	125	1,258
Settlement of asset retirement obligations	—	(101)
Deferred income taxes	1,142	(5,104)
Unrealized loss on derivative contracts	1,994	615
Accrued settlements on derivative contracts	919	(2,791)
Other	(10)	10
Changes in operating assets and liabilities:		
Receivables	(11,427)	(6,632)
Prepaid expenses and other current assets	(538)	(546)
Accounts payable and accrued expenses	18,516	4,498
State and federal income taxes payable	1,058	(141)
Net cash provided by operating activities	52,460	4,733
Cash flows from investing activities:		
Acquisition of oil and natural gas properties	(53,342)	(18,297)
Capital expenditures for oil and natural gas properties	(1,531)	(472)
Net cash used in investing activities	(54,873)	(18,769)
Cash flows from financing activities:		
Common stock dividends paid	(11,796)	(4,342)
Common stock repurchases, including stock surrendered for tax withholding	(38)	(7)
Borrowings under credit facility	34,000	7,000
Repayments of credit facility	(16,750)	(3,000)
Net cash provided by (used in) financing activities	5,416	(349)
Net increase (decrease) in cash and cash equivalents	3,003	(14,385)
Cash and cash equivalents, beginning of year	5,277	19,662
Cash and cash equivalents, end of year	$ 8,280	$ 5,277
Supplemental disclosures of cash flow information:		
Cash paid for interest on Senior secured credit facility	$ 523	$ 86
Cash paid for income taxes	6,294	758
Cash received from income tax refunds	3,223	142
Non-cash investing and financing transactions:		
Increase (decrease) in accrued purchases of property and equipment	1,094	(80)
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	7,807	2,883

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value				
Balances at June 30, 2020	32,957	$ 33	$ 41,291	$ 32,800	$ —	$ 74,124
Issuance of restricted common stock	561	1	(1)	—	—	—
Common stock repurchases, including stock surrendered for tax withholding	—	—	—	—	(7)	(7)
Retirements of treasury stock	(3)	—	(7)	—	7	—
Stock-based compensation	—	—	1,258	—	—	1,258
Net income (loss)	—	—	—	(16,438)	—	(16,438)
Common stock dividends paid	—	—	—	(4,342)	—	(4,342)
Balances at June 30, 2021	33,515	34	42,541	12,020	—	54,595
Issuance of restricted common stock	336	—	—	—	—	—
Forfeitures of restricted stock	(373)	(1)	1	—	—	—
Common stock repurchases, including stock surrendered for tax withholding	—	—	—	—	(38)	(38)
Retirements of treasury stock	(7)	—	(38)	—	38	—
Stock-based compensation	—	—	125	—	—	125
Net income (loss)	—	—	—	32,628	—	32,628
Common stock dividends paid	—	—	—	(11,796)	—	(11,796)
Balances at June 30, 2022	33,471	$ 33	$ 42,629	$ 32,852	$ —	$ 75,514

See accompanying notes to consolidated financial statements.

Note 1. Summary of Significant Events and Accounting Policies

Nature of Operations. Evolution Petroleum Corporation is an independent energy company focused on maximizing returns to stockholders through the ownership of and investment in onshore oil and natural gas properties in the United States. The Company's long-term goal is to maximize total shareholder return from a diversified portfolio of long-life oil and natural gas properties built through acquisitions and through selective development, production enhancement, and other exploitation efforts on its oil and natural gas properties.

The Company's producing properties consist of non-operated interests in the Delhi Holt-Bryant Unit in the Delhi Field in Northeast Louisiana, a CO_2 enhanced oil recovery ("EOR") project; non-operated interests in the Hamilton Dome Field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir; non-operated interests in the Barnett Shale located in North Texas, a natural gas producing property; non-operated interests in the Williston Basin in North Dakota, a producing oil and natural gas reservoir; non-operated interests in the Jonah Field in Sublette County, Wyoming; and small overriding royalty interests in four onshore Texas wells.

Principles of Consolidation and Reporting. The consolidated financial statements include the accounts of Evolution Petroleum Corporation and its wholly-owned subsidiaries (the "Company"). All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements for the previous year may include certain reclassifications to conform to the current presentation. To conform with the current year presentation, "*Accrued payables*" disclosed in Footnote 14, "*Additional Financial Information*" is included with *"Accrued liabilities and other*" instead of "*Accounts Payable*" at June 30, 2021 on the consolidated balance sheets and "*Net gain (loss) on derivative contracts*" is included with "*Other income and expenses*" instead of "*Total operating costs*" for the year ended June 30, 2021 on the consolidated statements of operations. These reclassifications have no impact on previously reported net income or stockholders' equity.

Risk and Uncertainties. None of the Company's ownership interests are operated by the Company and involve other third-party working interest owners. As a result, the Company has a limited ability to influence or control the operation or future development of such properties. However, the Company is proactive with its third-party operators to review spending and alter plans as appropriate.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally acceptable in the United States requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Significant estimates include (a) reserve quantities and estimated future cash flows associated with proved reserves, which may 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, (f) commitments and contingencies, and (g) accruals of crude oil, natural gas, and natural gas liquids ("NGL") revenues and expenses. The Company analyzes estimates and judgements based on historical experience and various other assumptions and information that are believed to be reasonable. Estimates and assumptions about future events and their effects cannot be predicted with certainty and, accordingly, these estimates may change as additional information is obtained, as new events occur, and as the Company's environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

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

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. The Company establishes 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, 2022 and 2021, no allowance for doubtful accounts was considered necessary.

Oil and Natural Gas Properties. The Company uses the full-cost method of accounting for its 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.

The depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of depletion, 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.

The capitalized costs of the Company's oil and natural gas properties, net of accumulated amortization and related deferred income taxes are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. Any excess over the full cost ceiling limitation is charged to expense as an impairment and is reflected as additional accumulated depletion, depreciation, and amortization or as a credit to oil and natural gas properties.

Oil and natural gas properties include costs that are excluded from depletion and amortization, which represent investments in unproved and unevaluated properties and include non-producing leasehold, geologic and geophysical costs associated with leasehold or drilling interests, and exploration drilling costs. These costs are excluded until the project is evaluated and proved reserves are established or impairment is determined. As of June 30, 2022 and 2021, the Company did not have any costs excluded from depletion and amortization.

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. Repair and maintenance costs are expensed in the period incurred.

Asset Retirement Obligations. An asset retirement obligation ("ARO") 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, the Company's 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 the Company's 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. The Company's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments, and debt. Except for derivatives, the carrying amounts of cash and cash equivalents, accounts receivable and accounts payable are short-term instruments and approximate fair value due to their highly liquid nature. The carrying amount of debt approximates fair value as the variable rates on the

Senior Secured Credit Facility, as defined in Note 6, *"Senior Secured Credit Facility,"* are market interest rates. 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 natural gas, discount rates, and volatility factors.

Concentrations of Credit Risk. The Company's primary concentrations of credit risk are the risks of uncollectible accounts receivable, and to a lesser extent, the non-performance by counterparties under the Company's derivative contracts, and cash and cash equivalent balances in excess of limits federally insured by the Federal Deposit Insurance Corporation.

Substantially all of the Company's accounts receivable as of June 30, 2022 is from crude oil, natural gas, and NGL sales to third-party purchasers in the oil and natural gas industry. The Company holds working interests in crude oil and natural gas properties for which a third-party serves as operator. As a non-operator, the Company primarily markets its production through its field operators, except at the Jonah Field, where the Company takes its natural gas and NGL production in-kind. As a non-operator, the Company is highly dependent on the success of its third-party operators and the decisions made in connection with their operations. The third-party operator sells the crude oil, natural gas, and NGLs to the purchaser, collects the cash, and distributes the cash to the Company. In the years ended June 30, 2022 and 2021, three operators each distributed over 10% of the Company's crude oil, natural gas and natural gas liquids revenues making up approximately 83% and 100% of total revenues for the years, respectively. The majority of the Company's crude oil, natural gas, and NGL production is sold to purchasers under short-term (less than 12 months) contracts at market-based prices.

Derivative Instruments. The Company follows Accounting Standards Codification ("ASC") 815, *Derivatives and Hedging* ("ASC 815"). From time to time, in accordance with the Company's policy and the covenants under the Senior Secured Credit Facility, it may hedge a portion of its forecasted crude oil, natural gas, and NGL 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 International Swap Dealers Association Master Agreement ("ISDA"); 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 contracts"* on the consolidated statements of operations.

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 geologic, 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 geologic 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 the Company's 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 the Company's financial statements. Material revisions to reserve estimates and/or significant changes in commodity prices could substantially affect the Company's estimated future net cash flows of its proved reserves. These changes could affect the Company's quarterly ceiling test calculation and could significantly affect its depletion rate.

Income Taxes. The Company recognizes deferred tax assets and liabilities based on the differences between the tax basis of assets and liabilities and its 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. The Company recognizes 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. The Company records 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. The Company grants restricted stock awards which entitle the recipient to all of the rights of a shareholder of the Company including non-forfeitable rights to receive all dividends or other distributions paid with respect to such share; therefore, it applies the two-class method of calculating basic and diluted earnings (loss) per share ("EPS") in accordance with ASC 260, *Earnings Per Share* ("ASC 260"). Basic EPS is computed by dividing earnings or loss available to common stockholders, after allocating undistributed earnings to participating securities, 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. Unvested performance-based restricted stock awards and unvested contingent restricted share units are only potentially dilutive if the awards meet their respective performance criteria as of the period end. The Company uses the treasury stock method to determine the effect of potentially dilutive common shares on diluted EPS, unless the effect would be anti-dilutive. The unamortized stock-based compensation expense related to unvested awards is assumed to be used to repurchase shares of 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. Awards with performance-based vesting restrictions are 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.

Correction of Immaterial Error

The Company has identified an issue related to its historical process of calculating the Company's EPS. The Company grants restricted stock awards which entitle the recipient to all of the rights of a shareholder of the Company including non-forfeitable rights to receive all dividends or other distributions paid with respect to such shares. Unvested restricted stock is forfeitable until earned and therefore not considered outstanding for basic EPS. Because restricted stock awards have the non-forfeitable right to share in dividends and earnings with common shareholders prior to vesting, the Company must apply the two-class method of allocating distributed and undistributed earnings to unvested restricted stock and outstanding common shares. Historically, it was identified by management that the Company had not been applying the two-class method of calculating basic and diluted EPS in accordance with ASC 260. Rather, the Company was considering all restricted stock grants as outstanding at the time of issuance in the calculation of EPS.

At March 31, 2022, the Company determined that its unvested restricted stock awards are participating securities which contain non-forfeitable rights to dividends. As a result, the Company is required to adjust *"Net income (loss) attributable to common stockholders"* to allocate dividends paid to unvested shares as well as undistributed earnings. In addition, the Company determined that its basic and diluted weighted average shares outstanding were also not adjusted correctly to reflect these participating securities.

The Company concluded the adjustments were immaterial to its 2021 annual and interim financial statements and its 2022 interim financial statements in accordance with the guidance in Securities and Exchange Commission ("SEC") Staff Accounting Bulletin ("SAB") No. 99, *Materiality* and SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in the Current Year Financial Statements.* The correction resulted in a decrease of $0.01 per basic and diluted share for the year ended June 30, 2021. See Note 13, "*Earnings (Loss) per Common Share*" for more details.

The Company noted the following adjustments to its Earnings (loss) per common share presentation for the year ended June 30, 2021 (in thousands, except per share amounts):

	Year Ended June 30, 2021
As reported:	
Net income (loss) for earnings per share calculation	$ (16,438)
Weighted average number of common shares outstanding — Basic	33,264
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share	33,264
Net earnings (loss) per common share — Basic	$ (0.49)
Net earnings (loss) per common share — Diluted	$ (0.49)
Revised:	
Net income (loss) for earnings per share calculation	$ (16,503)
Weighted average number of common shares outstanding — Basic	32,744
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share	32,744
Net earnings (loss) per common share — Basic	$ (0.50)
Net earnings (loss) per common share — Diluted	$ (0.50)

Recently Adopted Accounting Pronouncements

Income Taxes. In December 2019, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes* ("ASU 2019-12") as part of its initiative to reduce complexity in the accounting standards. The amendments in ASU 2019-12 remove certain exceptions related to the incremental approach for intra-period tax allocation and the general methodology for calculating income taxes in an interim period and reducing diversity in practice for the recognition of enacted changes in tax law. ASU 2019-12 also clarifies and simplifies other aspects of accounting for income taxes. ASU 2019-12 is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2020. Effective October 1, 2020, the Company adopted this new standard prospectively and it had no impact on the Company's consolidated financial statements.

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 ASU 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 Company is currently evaluating the impact of ASU 2016-13 but does not expect that it will have a material effect on the Company's financial position, results of operations, cash flows or disclosures.

Other accounting pronouncements that have recently been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company's financial position, results of operations, cash flows or disclosures.

Note 2. Leases

Operating leases are reflected as an operating lease right of use ("ROU") asset included in *"Other assets, net"*, and as a ROU liability in *"Accrued liabilities and other"* and *"Operating lease liability"* on the Company's 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 and are presented as "*General and administrative expenses*" in the consolidated statements of operations. 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 and having adequate liquidity, the Company has generally not entered into lease transactions. The Company's only operating lease is for corporate office space in Houston, Texas, effective May 1, 2019 and which expires November 30, 2022. The Company has no leases that meet the criteria for classification as a finance lease or a short-term lease.

The Company makes certain assumptions and judgments when evaluating a contract that meets the definition of a lease under ACS 842, *Leases*. At adoption, July 1, 2019, as the Company's operating lease did not provide an implicit rate, an incremental borrowing rate was calculated using the prime-rate-based borrowing rate under the Company's Senior Secured Credit Facility as the term facility was based on a similar lease term and is appropriately risk-adjusted. The lease term was determined by considering any option available to extend or to early terminate the lease which the Company believed was reasonably certain to be exercised.

The table below summarized the Company's leases for the years ended June 30, 2022 and 2021 (in thousands, except years and discount rate):

	Years Ended June 30,	
	2022	**2021**
Statements of Operations:		
Operating lease costs	$ 52	$ 52
Statements of Cash Flow:		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 62	$ 60
Balance Sheets:		
Operating lease ROU asset (included in other assets)	$ 21	$ 71
Accrued liabilities and other - current	26	64
Operating lease liability - long-term	—	21
Other:		
Weighted average remaining lease term in years	0.42	1.34
Weighted average discount rate	5.15 %	5.15 %

As of June 30, 2022, the future minimum lease payments associated with the Company's non-cancellable operating lease for office space are as follows (in thousands):

Fiscal Year	June 30, 2022
2023	$ 26
Total operating lease payments	26
Less: discount to present value	—
Total operating lease liabilities	26
Less: current operating lease liabilities	26
Non current operating lease liabilities	$ —

The Company 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).

Note 3. Revenue Recognition

The Company's revenues are primarily generated from its crude oil, natural gas and NGL production from the Delhi Field in Northeast Louisiana, the Hamilton Dome Field in Wyoming, the Barnett Shale properties located in North Texas, the Williston Basin properties in North Dakota, and the Jonah Field in Sublette County, Wyoming. Additionally, an overriding royalty interest retained in a past divestiture of Texas properties historically provided de minimis revenue, with the exception of the three months ended December 31, 2021 in which the Company received $1.1 million for past royalties that accumulated over a period of approximately three years. These past royalties were recorded as operating revenues within the consolidated statements of operations for the year ended June 30, 2022. Going forward, the Company expects de minimis revenue from these royalty interests. The following table disaggregates the Company's revenues by major product for the years ended June 30, 2022 and 2021 (in thousands):

	Years Ended June 30,	
	2022	2021
Revenues		
Crude oil	$ 52,683	$ 26,411
Natural gas	39,174	2,629
Natural gas liquids	17,069	3,662
Total revenues	$ 108,926	$ 32,702

As of June 30, 2022, as a non-operator, the Company did not take production in-kind and did not negotiate contracts with customers for its production from the Delhi Field, the Hamilton Dome Field, the Barnett Shale properties or the Willison Basin properties. The Company recognizes crude oil, natural gas, and NGL production revenue at the point in time when custody and title ("control") of the product transfers to the customer. The sales of oil and natural gas are made under contracts which the Company's third-party operators of its wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company receives payment from the sale of oil and natural gas production one to two months after delivery.

In the Jonah Field, the Company has elected to take its natural gas and NGL working interest production in-kind and markets separately to different purchasers for natural gas and to Enterprise Products Partners L.P. ("Enterprise") for its NGLs.

Judgments made in applying the guidance in ASC 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 completed 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 by field operators before distributing the Company’s share one to two months after production has occurred, which is typical in the oil and natural gas 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. To estimate accounts receivable from operators’ contracts with customers, the Company uses knowledge of its properties, information from field operators, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors as the basis for these estimates. Because the contractual performance obligations have been satisfied and an unconditional right to consideration exists as of the balance sheet date, the Company recognized amounts due from contracts with field operators as *“Receivables from crude oil, natural gas, and natural gas liquids sales”* on the consolidated balance sheets. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser as remitted to the Company by field operators.

Note 4. Acquisitions

On April 1, 2022, the Company closed the acquisition of non-operated interests in the Jonah Field in Sublette County, Wyoming from Exaro Energy III, LLC (the “Jonah Field Acquisition”). After taking into account customary closing adjustments and an effective date of February 1, 2022, total cash consideration for the Jonah Field Acquisition was $26.4 million (“Jonah Purchase Agreement”). The Company accounted for this transaction as an asset acquisition and allocated $24.8 million of the purchase price (including $0.2 million of transaction costs) to proved oil and natural gas properties. Approximately, $1.6 million of the consideration transferred related to deposits transferred to the Company at closing, the largest related to a $1.2 million deposit with Enterprise for a gas gathering contract which was recorded to “*Other assets, net*” on the consolidated balance sheets. In addition, the Company recognized $3.0 million in non-cash asset retirement obligations. The transaction was funded with cash on hand and $17.0 million in borrowings under the Company’s Senior Secured Credit Facility.

On January 14, 2022, the Company completed the acquisition of non-operated working interests in the Williston Basin in North Dakota from Foundation Energy Fund VII-A, LP and Foundation Energy Management, LLC (the “Williston Basin Acquisition”). After taking into account customary closing adjustments and an effective date of June 1, 2021, cash consideration was $25.2 million which included $0.3 million of capitalized transaction costs related to the acquisition. The Company accounted for the transaction as an asset acquisition and allocated all of the purchase price (including capitalized transaction costs) to proved oil and natural gas properties. The Company also recognized $2.4 million in non-cash asset retirement obligations. The transaction was funded with cash on hand and $16.0 million in borrowings under the Company’s Senior Secured Credit Facility.

On May 7, 2021, the Company acquired an approximate 17% average net working interest and a 14% average net revenue interest in non-operated oil and natural gas properties in the Barnett Shale from Tokyo Gas Americas for net cash consideration of $17.4 million, after taking into account customary closing adjustments, and also recognized $2.8 million in non-cash asset retirement obligations (the “Barnett Shale Acquisition”). The Company determined that the properties acquired did not meet the definition of a business; therefore, the transaction was accounted for as an asset acquisition. During the nine months ended March 31, 2022, the Company recorded a downward purchase price adjustment of $0.9 million related to its acquisition of the Barnett Shale properties as a result of the completion of the final settlement statement.

In accordance with the FASB's authoritative guidance on asset acquisitions, the Company allocated the cost of the acquisition to the assets acquired and liabilities assumed based on a relative fair value basis of the assets acquired and liabilities assumed, with no recognition of goodwill or bargain purchase gain recorded. Incremental legal and professional fees related directly to the acquisitions were capitalized as part of the acquisition cost. The fair value is 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). Fair value measurements also utilize market assumptions of market participants.

Note 5. Property and Equipment

Property and equipment as of June 30, 2022 and 2021 consisted of the following (in thousands):

	June 30, 2022	June 30, 2021
Oil and natural gas properties		
Property costs subject to amortization	$ 188,634	$ 129,123
Less: Accumulated depletion, depreciation, and amortization	(78,126)	(70,607)
Oil and natural gas properties, net	$ 110,508	$ 58,516
Other property and equipment		
Furniture, fixtures and office equipment, at cost	$ 148	$ 155
Less: Accumulated depreciation	(148)	(144)
Other property and equipment, net	$ —	$ 11

As of June 30, 2022 and 2021, all oil and natural gas property costs were subject to amortization. Depletion on oil and natural gas properties was $7.5 million and $4.9 million for the years ended June 30, 2022 and 2021, respectively. Depreciation on other properties and equipment was less than $0.1 million for both the years ended June 30, 2022 and 2021.

During the years ended June 30, 2022 and 2021, the Company incurred development capital expenditures of $2.6 million and $0.6 million, respectively. In addition, during the year ended June 30, 2022, the Company recorded a downward $0.9 million purchase adjustment related to its acquisition of the Barnett Shale properties. The Company received $0.9 million during the year ended June 30, 2022 primarily related to effective date net revenues received from the previous owner of the properties.

The Company uses the full cost method of accounting for its investments in oil and natural gas properties. All costs of acquisition, exploration, and development of oil and natural gas reserves are capitalized as the cost of oil and natural gas and properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs result in an impairment charge.

At June 30, 2022, the ceiling test value of the Company's reserves was calculated based on the first-day-of-the-month average for the 12-months ended June 30, 2022 of the West Texas Intermediate ("WTI") crude oil spot price of $85.82 per barrel and Henry Hub natural gas spot price of $5.19 per MMBtu, adjusted by market differentials by field. The net price per barrel of NGLs was $44.24, which was based on historical differentials to WTI as NGLs do not have any single comparable reference index price. Using these prices, the Company's net book value of oil and natural gas properties as of June 30, 2022 did not exceed the current ceiling. There was no impairment on oil and natural gas properties for the year ended June 30, 2022.

At June 30, 2021, the ceiling test value of the Company's reserves was calculated based on the first-day-of-the-month average for the 12-months ended June 30, 2021 of the WTI crude oil spot price of $49.72 per barrel and Henry Hub natural gas spot price of $2.46 per MMBtu, adjusted by market differentials by field. The net price per barrel of NGLs was $19.81, which was based on historical differentials to WTI as NGLs do not have any single comparable reference index price. Using these prices, the Company's net book value of oil and natural gas properties at June 30, 2021 did not exceed the current ceiling. At December 31, 2020 and September 30, 2020, the Company recorded ceiling test impairment charges of $15.2 million and $9.6 million, respectively. The ceiling test impairments were driven by decreases in the first-day-of-the-month average for crude oil used in the ceiling test calculation, from $47.37 per barrel at June 30, 2020 to $43.63 per barrel at September 30, 2020 to $39.54 per barrel at December 31, 2020. For the year ended June 30, 2021, the Company recorded total impairment on oil and natural gas properties of $24.8 million recorded as *"Impairment of proved property"* on the consolidated statements of operations.

Note 6. Senior Secured Credit Facility

On April 11, 2016, the Company entered into a three-year, senior secured reserve-based credit facility, as amended, (the "Senior Secured Credit Facility") with MidFirst Bank in an amount up to $50.0 million with a current borrowing base of $50.0 million. On November 2, 2020, the Company entered into the Fifth Amendment to the Senior Secured Credit Facility extending the maturity to April 9, 2024. The borrowing base will be redetermined semiannually, with the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of the Company's oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. The Senior Secured Credit Facility included a placement fee of 0.50% on the initial borrowing base amounting to $50.0 million and carries a commitment fee of 0.25% per annum on the undrawn portion of the borrowing base. Any borrowings under the Senior Secured Credit Facility will bear interest, at the Company's option, at either London Interbank Offered Rate ("LIBOR") plus 2.75%, subject to a minimum LIBOR of 0.25%, or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%.

The Company may elect, at its option, to prepay any borrowings outstanding under the Senior Secured Credit Facility without premium or penalty. Amounts outstanding under the Senior Secured Credit Facility are guaranteed by the Company's direct and indirect subsidiaries and secured by a security interest in substantially all of the properties of the Company and its subsidiaries. Borrowings under the Senior Secured Credit Facility may be used for the acquisition and development of oil and natural gas properties, investments in cash flow generating properties complimentary to the production of oil and natural gas, and for letters of credit or other general corporate purposes.

The Senior Secured Credit Facility contains certain events of default, including non-payment; breaches or representation and warranties; non-compliance with covenants; cross-defaults to material indebtedness; voluntary or involuntary bankruptcy; judgments and change in control. The Senior Secured Credit Facility also contains financial covenants including a requirement that the Company maintain, as of the last day of each fiscal quarter, (i) a maximum total leverage ratio of not more than 3.00 to 1.00, (ii) a current ratio of not less than 1.00 to 1.00, and (iii) a consolidated tangible net worth of not less than $40.0 million, each as defined in the Senior Secured Credit Facility. As of June 30, 2022, the Company had $21.3 million borrowings outstanding under its Senior Secured Credit Facility, resulting in $28.7 million of available borrowing capacity. As of June 30, 2022, the Company was in compliance with the financial covenants under the Senior Secured Credit Facility.

The Company is currently working on its annual redetermination with MidFirst Bank. It expects that the borrowing base will remain at $50.0 million and the Margined Collateral Value, as defined in the Ninth Amendment to the Senior Secured Credit Facility, will be set at $125.0 million. The Company is required to enter into hedges on a rolling 12-month basis when the borrowings exceed 25% of the Margined Collateral Value. Based on the current amount outstanding, the utilization percentage under the required hedging covenant is below the minimum utilization threshold of 25% and as a result the Company is not required to enter into additional hedges at this time.

On February 7, 2022, the Company entered into the Ninth Amendment to the Senior Secured Credit Facility. This amendment, among other things, modified the definition of utilization percentage related to the required hedging covenant such that for the purposes of determining the amount of future production to hedge, the utilization of the Senior Secured Credit Facility will be based on the Margined Collateral Value, as defined in the agreement, to the extent it exceeds the borrowing base then in effect. This amendment also required the Company to enter into hedges for the next 12-month period ending February 2023, covering 25% of expected crude oil and natural gas production over that period.

On November 9, 2021, the Company entered into the Eighth Amendment to the Senior Secured Credit Facility. This amendment, among other things, increased the borrowing base to $50.0 million and added a hedging covenant whereby the Company must hedge a minimum of 25% to 75% of future production on a rolling 12-month basis when 25% or more of the borrowing base is utilized. The hedging covenant was amended in the Ninth Amendment, as discussed above.

On August 5, 2021 the Company entered into the Seventh Amendment to the Senior Secured Credit Facility which, among other things, added definitions for the terms “Acquired Entity or Mineral Interests” and “Acquired Entity or Mineral Interests EBITDA Adjustment.” Additionally, the consolidated tangible net worth covenant level was reduced to $40.0 million from $50.0 million.

On January 5, 2021, and effective as of December 28, 2020, the Company entered into the Sixth Amendment to the Senior Secured Credit Facility which replaced the debt service coverage ratio (as defined therein) maintenance covenant with a new covenant requiring current ratio (as defined therein) of not less than 1.00 to 1.00.

Note 7. Income Taxes

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

There were no unrecognized tax benefits, nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2022 and 2021. The Company believes that it has 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 its 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 fiscal years ended June 30, 2018 through June 30, 2021 for federal tax purposes and for the fiscal years ended June 30, 2017 through June 30, 2021 for state tax purposes. To the extent the Company utilizes net operating losses (“NOLs”) generated in earlier years, such earlier years may also be subject to audit.

Income tax (expense) benefit for the years ended June 30, 2022 and 2021 is comprised of the following (in thousands):

	June 30, 2022	June 30, 2021
Current:		
Federal	$ (6,309)	$ 334
State	(1,062)	(454)
Total current income tax (expense) benefit	(7,371)	(120)
Deferred:		
Federal	(913)	3,987
State	(229)	1,117
Total deferred income tax (expense) benefit	(1,142)	5,104
Total income tax (expense) benefit	$ (8,513)	$ 4,984

For the year ended June 30, 2022 the Company recognized income tax expense of $8.5 million and had an effective tax rate of 20.7% compared to an income tax benefit of $5.0 million and an effective tax rates of 23.3% for the year ended June 30, 2021.

In certain prior years, the Company undertook a project to seek potential cash tax savings opportunities identifying available Enhanced Oil Recovery credits (“EOR credits”) related to its interests in the Delhi Field. To take advantage of the EOR credits, the Company amended federal and state tax returns for the years ended June 30, 2017 and 2018 and incorporated the associated impacts into its 2019 tax returns. Principally as a result of the EOR credits, the Company recorded a net tax benefit of $2.8 million during fiscal 2020, all of which was received during the year ended June 30, 2022. During year ended June 30, 2022, the Company recognized an income tax benefit of $0.4 million attributable to the EOR credit.

The Company's effective tax rate will typically differ from the statutory federal rate as a result of state income taxes, primarily in the states of Louisiana and Texas, due to percentage depletion in excess of basis, valuation allowance, enhanced oil recovery credit, and other permanent differences. The following table presents the reconciliation of the Company's income taxes calculated at the statutory federal tax rate to the income tax (expense) benefit (in thousands).

	June 30, 2022	% of Income Before Income Taxes	June 30, 2021	% of Income Before Income Taxes
Income tax (expense) benefit computed at the statutory federal rate:	$ (8,640)	21.0 %	$ 4,499	21.0 %
Reconciling items:				
Return to provision adjustments	(2)	— %	(20)	(0.1)%
Depletion in excess of tax basis	190	(0.5)%	176	0.8 %
State income taxes, net of federal tax benefit	(1,020)	2.5 %	523	2.4 %
Permanent differences related to stock-based compensation and other	3	— %	(55)	(0.3)%
Federal valuation allowance	623	(1.5)%	(570)	(2.7)%
EOR credit benefit	377	(0.9)%	336	1.6 %
Other	(44)	0.1 %	95	0.6 %
Income tax (expense) benefit	$ (8,513)	20.7 %	$ 4,984	23.3 %

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of net deferred income tax assets (liabilities) recognized are as follows (in thousands):

	June 30, 2022	June 30, 2021
Deferred tax assets:		
Non-qualified stock-based compensation	$ 106	$ 310
Net operating loss carry-forwards and other carry-forwards	8	365
Derivative losses	427	—
Asset retirement obligations	3,128	1,285
Other deferred tax assets	238	161
Gross deferred tax assets	3,907	2,121
Valuation allowance	—	(862)
Net deferred tax assets	3,907	1,259
Deferred tax liability:		
Oil and natural gas properties	(11,006)	(7,216)
Total deferred tax liability	(11,006)	(7,216)
Net deferred tax liability	$ (7,099)	$ (5,957)

As of June 30, 2022, the Company had a federal tax loss carryforward of approximately $0.6 million that it acquired through a reverse merger in May 2004. The majority of the tax loss carryforwards from the reverse merger expired without being utilized. The remaining deferred tax asset and valuation allowance of $0.1 million related to the portion of the NOLs that were limited by IRC Section 382 was written off during the year ended June 30, 2022. The Company has considered all positive and negative evidence to assess the likelihood that it will be able to realize its deferred tax assets. Realization is dependent on generating sufficient taxable income over the period the deferred tax assets are deductible. For the three-year period ending June 30, 2022, the Company is in a cumulative income position. Based on the weight of available evidence, the Company believes that it is more likely than not that the deferred tax assets will be realized. As result, the Company has released the valuation allowance of $0.6 million.

Note 8. Derivatives

The Company is exposed to certain risks relating to its ongoing business operations, including commodity price risk and interest rate risk. In accordance with the Company's policy and the requirements under the Senior Secured Credit

Facility (as discussed in Note 6, *"Senior Secured Credit Facility"*), it may hedge or may be required to hedge a varying portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company's hedge policies and objectives may change significantly as its operational profile changes. The Company does not enter into derivative contracts for speculative trading purposes.

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, 2022, the Company did not post collateral under any of its derivative contracts as they are secured under the Company's Senior Secured Credit Facility.

The Company has in the past and may utilize in the future costless put/call collars and fixed-price swaps to hedge a portion of its anticipated future production. 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. 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. 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.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820, *Fair Value Measurement* ("ASC 820") and included in the consolidated balance sheets as assets or liabilities. The *"Derivative contract assets"* and *"Derivative contract liabilities"* represent the difference between the market commodity prices and the hedged prices for the remaining volumes of production hedges as of June 30, 2022 (the "mark-to-market valuation"). The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of June 30, 2022 and 2021 (in thousands):

Derivatives not designated as hedging contracts under ASC 815	Balance sheet location	Derivative Contract Asset June 30, 2022	Derivative Contract Asset June 30, 2021	Balance sheet location	Derivative Contract Liability June 30, 2022	Derivative Contract Liability June 30, 2021
Commodity contracts	Current assets - derivative contract assets	$ 170	$ —	Current liabilities - derivative contract liabilities	$ 2,164	$ —
Commodity contracts	Other assets - derivative contract assets	—	—	Long term liabilities - derivative contract liabilities	—	—
Total derivatives not designated as hedging contracts under ASC 815		$ 170	$ —		$ 2,164	$ —

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations (in thousands). *"Realized gain (loss) on derivative contracts"* represents all receipts (payments) on derivative contracts settled during the period. *"Unrealized gain (loss) on derivative contracts"* represents the net change in the mark-to-market valuation of the derivative contracts.

Derivatives not designated as hedging contracts under ASC 815	Location of gain (loss) recognized in income on derivative contracts	Years Ended June 30, 2022	Years Ended June 30, 2021
Commodity contracts:			
Realized gain (loss) on derivative contracts	Other income and expenses - net gain (loss) on derivative contracts	$ (1,769)	$ (2,526)
Unrealized gain (loss) on derivative contracts	Other income and expenses - net gain (loss) on derivative contracts	(1,994)	1,911
Total net gain (loss) on derivative contracts		$ (3,763)	$ (615)

As of June 30, 2022, the Company had the following open crude oil and natural gas derivative contracts:

Period	Instrument	Commodity	Volumes in MMBTU/Bbl	Weighted Average Floor Price per MMBTU/Bbl	Weighted Average Ceiling Price per MMBTU/Bbl
July 2022 - October 2022	Collar	Natural Gas	471,640	$ 3.75	$ 5.05
November 2022 - February 2023	Collar	Natural Gas	443,750	3.75	7.30
July 2022 - October 2022	Collar	Natural Gas	317,579	5.25	6.67
November 2022 - March 2023	Collar	Natural Gas	374,072	5.25	7.50
July 2022 - February 2023	Collar	Crude Oil	122,389	70.00	87.50

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The following table shows the potential effects of master netting arrangements on the fair value of the Company's derivative contracts as of June 30, 2022 and 2021 (in thousands):

	Derivative Contract Asset		Derivative Contract Liability	
Offsetting of Derivative Assets and Liabilities	June 30, 2022	June 30, 2021	June 30, 2022	June 30, 2021
Gross amounts presented in the Consolidated Balance Sheet	$ 170	$ —	$ 2,164	$ —
Amounts not offset in the Consolidated Balance Sheet	(170)	—	(170)	—
Net amount	$ —	$ —	$ 1,994	$ —

The Company enters into an 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 9. 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. 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 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, and 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. The following table, set forth by level within the fair value hierarchy, shows the Company's financial assets and liabilities that were accounted for at fair value as of June 30, 2022 (in thousands). The Company did not have any open positions as of June 30, 2021.

	June 30, 2022			
	Level 1	Level 2	Level 3	Total
Assets				
Derivative contract assets	$ —	$ 170	$ —	$ 170
Liabilities				
Derivative contract liabilities	$ —	$ 2,164	$ —	$ 2,164

Derivative contracts listed above as Level 2 include costless put/call collars that are carried at fair value. The Company records the net change in fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 8, *"Derivatives*," for additional discussion of derivatives.

The Company's derivative contracts are with large utilities with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts; however, the Company does not anticipate such nonperformance.

Other Fair Value Measurements. The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash and cash equivalents, accounts receivable, and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Senior Secured Credit Facility approximates carrying value because the interest rates approximate current market rates.

The Company follows the provisions of ASC 820, for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial measurement and any subsequent revision of ARO for which fair value is calculated using discounted future cash flows derived from historical costs and management's expectations of future cost environments. Significant Level 3 inputs used in the calculation of ARO 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. See Note 10, *"Asset Retirement Obligations*," for a reconciliation of the beginning and ending balances of the liability for the Company's ARO.

Note 10. Asset Retirement Obligations

The Company's ARO represents the estimated present value of the amount expected to be incurred to plug, abandon, and remediate its oil and natural gas properties at the end of their productive lives in accordance with applicable laws and regulations. The Company records the ARO liability on the consolidated balance sheets and capitalizes the cost in *"Oil and natural gas properties, net"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and amortization"* expense in the consolidated statements of operations.

The following is a reconciliation of the activity related to the Company's ARO liability (inclusive of the current portion) for the years ended June 30, 2022 and 2021 (in thousands):

	Years Ended	
	June 30, 2022	June 30, 2021
Asset retirement obligations — beginning of period	$ 5,583	$ 2,589
Liabilities incurred	219	—
Liabilities settled[(1)]	(17)	(99)
Liabilities acquired[(2)]	5,400	2,806
Accretion of discount	531	210
Revisions of previous estimates[(3)]	2,205	77
Asset retirement obligations — end of period	13,921	5,583
Less: current asset retirement obligations	(22)	(44)
Long-term portion of asset retirement obligations	$ 13,899	$ 5,539

(1) Primarily related to abandonment of one Delhi Field and one Hamilton Dome Field well for the year ended June 30, 2022 and abandonment of two non-scheduled Delhi Field wells for the year ended June 30, 2021.

(2) Liabilities acquired during the years ended June 30, 2022 and 2021 were primarily due to the Jonah Field Acquisition and the Williston Basin Acquisition in 2022, and the Barnett Shale Acquisition in 2021. See Note 4, *"Acquisitions,"* for additional information on the Company's acquisition activities.

(3) Primarily related to upward revisions for increased estimates for the year ended June 30, 2022 and two difficult-to-plug Delhi Field wells for the year ended June 30, 2021.

Note 11. Commitments and Contingencies

The Company is subject to various claims and contingencies in the normal course of business. In addition, from time to time, the Company receives communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdictions in which the Company operates. The Company discloses such matters if it believes there is a reasonable possibility that a future event or events will confirm a material loss through impairment of an asset or the incurrence of a material liability. The Company accrues a material loss if it believes it probable that a future event or events will confirm a loss and the loss is reasonably estimable. Furthermore, the Company will disclose any matter that is unasserted if it considers it probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable and material in amount. The Company expenses legal defense costs as they are incurred.

Note 12. Stockholders' Equity

Common Stock

As of June 30, 2022, the Company had 33,470,710 shares of common stock outstanding.

The Company began paying quarterly cash dividends on common stock in December 2013. As of June 30, 2022, the Company has cumulatively paid over $86.3 million in cash dividends. The Company paid dividends of $11.8 million and $4.3 million to its common stockholders during the years ended June 30, 2022 and 2021, respectively. The following table reflects the dividends paid within the respective quarterly periods:

	Fiscal Year	
	2022	2021
Fourth quarter ended June 30,	$ 0.100	$ 0.050
Third quarter ended March 31,	0.100	0.030
Second quarter ended December 31,	0.075	0.025
First quarter ended September 30,	0.075	0.025

On September 12, 2022, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2022. This represents a 20% increase over the $0.10 per common share dividend paid in the fourth quarter of fiscal year 2022. Also, on September 8, 2022, the Board of Directors authorized a share repurchase program, under which the Company is approved to repurchase up to $25 million of its common stock through December 31, 2024. The Company intends to fund repurchases from working capital and cash provided by operating activities. The Board of Directors along with the management team believe that a share repurchase program is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will depend on a variety of factors, including management's assessment of the intrinsic value of the Company's shares, the market price of the Company's common stock, general market and economic conditions, and applicable legal requirements. The value of shares authorized for repurchase by the Company's Board of Directors does not require the Company to repurchase such shares or guarantee that such shares will be repurchased, and the program may be suspended, modified, or discontinued at any time without prior notice. Refer to Note 15, *"Subsequent Events,"* for a further discussion.

In May 2015, the Board of Directors approved a share repurchase program covering up to $5.0 million of the Company's common stock. Since inception of the program through June 30, 2020, the Company spent $4.0 million to repurchase 706,858 common shares at an average price of $5.72 per share. This program has since concluded and there were no shares purchased under this program during the years ended June 30, 2022 and 2021. Under the program's terms, shares were repurchased only on the open market and in accordance with the requirements of the SEC. Such shares were initially recorded as treasury stock, then subsequently cancelled.

During the years ended June 30, 2022 and 2021, the Company also acquired treasury stock from holders of newly vested stock-based awards to fund the recipients' payroll tax withholding obligations. The treasury shares were subsequently cancelled. Such shares were valued at fair market value on the date of vesting. The following table shows all treasury stock purchases in the last two fiscal years (in thousands, except per share amounts):

	Years Ended	
	June 30, 2022	June 30, 2021
Number of treasury shares acquired	7	3
Average cost per share	$ 5.09	$ 2.79
Total cost of treasury shares acquired	$ 38	$ 7

Expected Tax Treatment of Dividends

For the fiscal year ended June 30, 2021, all common stock dividends for that fiscal year were treated for tax purposes as qualified dividend income to the recipients. Based on its current projections for the fiscal year ended June 30, 2022, the Company expects all common stock dividends for such period to be treated as qualified dividend income to the recipients.

Stock-Based Incentive Plan

The Evolution Petroleum Corporation 2016 Equity Incentive Plan ("2016 Plan"), approved at the December 2016 annual meeting of stockholders, authorizes the issuance of 1.1 million shares of common stock prior to its expiration on December 8, 2026. Incentives under the 2016 Plan may be granted to employees, directors, and consultants of the Company in any one or a combination of the following forms: incentive stock options and non-statutory stock options, stock appreciation rights, restricted stock awards and restricted stock unit awards, performance share awards, performance cash awards, and other forms of incentives valued in whole or in part by reference to, or otherwise based on, the Company's common stock, including its appreciation in value. On December 9, 2020, an amendment to the 2016 Plan was approved by its stockholders which increased the number of shares available for issuance by 2.5 million shares to a maximum of 3.6 million shares. As of June 30, 2022 and 2021, approximately 1.8 million shares and 2.2 million shares, respectively, remained available for grant under the 2016 Plan.

The Company estimates the fair value of stock-based compensation awards on the grant date to provide the basis for future compensation expense. For the years ended June 30, 2022, and 2021, the Company recognized $0.1 million and $1.3 million, respectively, related to stock-based compensation expense recorded as a component of "*General and* *administrative expenses*" on the consolidated statements of operations. During the year ended June 30, 2022, the Company recognized a reduction of $1.2 million to stock-based compensation expense for the forfeiture of unvested shares in connection with severance.

Time-Vested Restricted Stock Awards

Time-vested restricted stock awards contain service-based vesting conditions and expire after a maximum of four years from the date of grant if unvested. The common shares underlying these awards are issued on the date of grant and participate in dividends paid by the Company. These service-based awards vest with continuous employment by the Company, generally in annual installments over terms of three to four years. Awards to the Company's directors have one-year cliff vesting. For such awards, grant date fair value is based on market value of the Company's common stock at the time of grant. This value is then amortized ratably over the service period. Previously recognized amortization expense subsequent to the last vesting date of an award is reversed in the event that the holder has no longer rendered service to the Company resulting in forfeiture of the award.

Performance-Based Restricted Stock Awards and Performance-Based Contingent Stock Units

Performance-based restricted stock awards and performance-based contingent stock units contain market-based vesting conditions based on the price of the Company's common stock, the intrinsic value indexed solely to its common stock and the intrinsic value indexed to its common stock compared to the performance of the common stock of its peers. The common shares underlying the Company's performance-based restricted stock awards are issued on the date of grant and participate in dividends paid by the Company and expire after a maximum of four years from the date of grant if unvested. Performance-based contingent share units do not participate in dividends and shares are only issued in part or in full upon the attainment of vesting conditions which generally have a lower probability of achievement and expire after a maximum of four years from the date of grant if unvested. Shares underlying performance-based contingent share units are reserved from the 2016 Plan. Performance-based restricted stock awards and contingent restricted stock units 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 the Company compares its performance and/or the Company's absolute total stock return. For certain awards, this Monte Carlo simulation also provides an expected vesting term. Stock-based compensation is recognized ratably over the expected vesting period, so long as the award holder remains an employee of the Company. Previously recognized compensation expense is only reversed for the awards with market-based vesting conditions if the requisite service period is not rendered by the holder resulting in forfeiture of the award.

Vesting of grants with performance-based vesting conditions is dependent on the future price of the Company's common stock. Such awards vest in part or in full if the trailing total returns on the Company's common stock for a specified three-year period exceed the corresponding total returns of various quartiles of indices consisting of peer companies or, in some cases, vest when the average of the Company's closing common stock price over a defined measurement period meets or exceeds a required common stock price.

During the year ended June 30, 2022, the Company granted a total of 0.4 million equity awards that included 0.2 million shares of time-vested restricted stock primarily to employees under its long-term incentive pay program together with annual awards to its directors, 0.1 million shares of performance-based restricted stock and 0.1 million performance-based contingent shares unit awards.

During the year ended June 30, 2021, the Company granted a total of 0.7 million equity awards that included 0.3 million time-vested restricted stock primarily to employees under its long term incentive program together with annual awards to its directors, 0.3 million performance-based restricted stock awards, and 0.1 million performance-based contingent share unit awards. In addition to the foregoing, in connection with the retirement of the Company's former Chief Financial Officer, vesting was accelerated as to approximately 0.1 million aggregate shares of service- and performance-based equity awards (with a weighted average fair value of $5.15 per share) which, for accounting purposes, was treated as a cancellation and replacement of the same number of awards which had a fair value of $2.79 per share.

For performance-based awards granted during the years ended June 30, 2022 and 2021, the assumptions used in the Monte Carlo simulation valuations were as follows:

	Years Ended June 30,	
	2022	2021
Weighted average fair value of performance-based awards granted	$ 3.10	$ 3.08
Risk-free interest rate	0.53% to 0.60%	0.23 %
Expected term in years	2.64 to 2.79	2.56
Expected volatility	64.7 %	56.9 %
Dividend yield	4.8% to 6.3%	3.2 %

Unvested restricted stock awards as of June 30, 2022 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Time-vested awards	241,089	$ 5.10
Performance-based awards	100,122	3.19
Unvested at June 30, 2022	341,211	$ 4.54

The following table sets forth the restricted stock transactions for the years ended June 30, 2022 and 2021:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense (In thousands)	Weighted Average Remaining Amortization Period (Years)	Aggregate Intrinsic Value [(1)] (In thousands)
Unvested at June 30, 2020	285,028	$ 5.53			
Time-vested shares granted	365,479	2.97			
Performance-based shares granted	246,160	3.07			
Vested	(176,848)	5.09			
Forfeited	(50,524)	5.15			
Unvested at June 30, 2021	669,295	3.37	$ 1,531	1.9	$ 3,320
Service-based shares granted	205,077	5.88			
Performance-based shares granted	131,293	3.31			
Vested	(291,227)	3.77			
Forfeited	(373,227)	3.35			
Unvested at June 30, 2022	341,211	$ 4.54	$ 1,092	2.1	$ 1,863

(1) *The intrinsic value of restricted stock was calculated as the closing market price on June 30, 2022 and 2021 of the underlying stock multiplied by the number of restricted shares that would be issuable. The total fair value of shares vested was $1.5 million and $0.6 million for the years ended June 30, 2022 and 2021, respectively.*

Unvested contingent restricted stock units table below consists solely of performance-based awards for the year ended June 30, 2022 and 2021:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense (In thousands)	Weighted Average Remaining Amortization Period (Years)	Aggregate Intrinsic Value [(1)] (In thousands)
Unvested at June 30, 2020	200,000	$ 3.50			
Performance-based awards granted	123,080	1.76			
Unvested at June 30, 2021	323,080	2.84	$ 169	2.0	$ 1,602
Performance-based awards granted	65,649	2.67			
Vested	—	—			
Forfeited	(338,667)	2.90			
Expired	—	—			
Unvested at June 30, 2022	50,062	$ 2.21	$ 68	1.7	$ 273

(1) *The intrinsic value of contingent restricted stock units was calculated as the closing market price on June 30, 2022 and 2021 of the underlying stock multiplied by the number of restricted shares that would be issuable.*

Note 13. Earnings (Loss) per Common Share

The following table sets forth the computation of basic and diluted earnings (loss) per common share, reflecting the application of the two-class method (in thousands, except per share amounts):

	Years Ended	
	June 30, 2022	June 30, 2021
Numerator		
Net income (loss)	$ 32,628	$ (16,438)
Undistributed earnings allocated to unvested restricted stock	(673)	(65)
Net income (loss) for earnings per share calculation	$ 31,955	$ (16,503)
Denominator		
Weighted average number of common shares outstanding — Basic	32,952	32,744
Effect of dilutive securities:		
Unvested restricted stock	354	—
Contingent restricted stock grants	—	—
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share	33,306	32,744
Net earnings (loss) per common share — Basic	$ 0.97	$ (0.50)
Net earnings (loss) per common share — Diluted	$ 0.96	$ (0.50)

Unvested Restricted Stock (both service-based and performance-based), totaling approximately 20,000 for the year ended June 30, 2022 were not included in the computation of diluted earnings per common share because the effect would have been anti-dilutive.

Unvested Restricted Stock (both service-based and performance-based), totaling 0.3 million for the year ended June 30, 2021, were not included in the computation of diluted earnings per common share because the effect would have been anti-dilutive due to the net loss.

In addition, unvested performance-based restricted stock and unvested contingent restricted share units that would not meet the performance criteria as of the period end are excluded from the computation of diluted earnings per common share.

Note 14. Additional Financial Statement Information

Certain amounts on the consolidated balance sheets are comprised of the following (in thousands):

	June 30, 2022	June 30, 2021
Prepaid expenses and other current assets:		
Receivable for settlement proceeds from acquisitions(1)	$ 2,263	$ —
Prepaid insurance	743	366
Prepaid federal and state income taxes	8	97
Prepaid subscription and licenses	38	108
Carryback of EOR tax credit	347	416
Prepaid other	439	49
Total prepaid expenses and other current assets	$ 3,838	$ 1,036
Other assets, net:		
Deposit(2)	$ 1,150	$ —
Right of use asset under operating lease(3)	161	161
Less: Accumulated amortization of right of use asset	(140)	(90)
Other assets, net	$ 1,171	$ 71
Accrued liabilities and other:		
Accrued payables	$ 8,070	$ 3,996
Accrued incentive and other compensation	626	631
Accrued royalties payable(4)	1,517	—
Accrued severance	332	53
Accrued franchise taxes	58	35
Accrued ad valorem taxes	120	108
Accrued settlements on derivative contracts	919	—
Operating lease liability(3)	26	64
Asset retirement obligations due within one year	22	44
Accrued - other	203	12
Total Accrued liabilities and other	$ 11,893	$ 4,943

(1) Receivables related to customary purchase adjustments of $1.6 million and $0.7 million related to the Jonah Field Acquisition and Williston Basin Acquisition, respectively. See Note 4, *"Acquisitions"* for a further discussion.

(2) The deposit of $1.2 million is related to a long-term gas gathering deposit with Enterprise entered into at closing of the Jonah Field Acquisition. See Note 4, *"Acquisitions"* for additional information.

(3) Operating leases are reflected as an operating lease ROU asset included in *"Other assets, net"* and as an operating lease liability, current in *"Accrued liabilities and other"* and *"Operating lease liability"* on the Company's consolidated balance sheets. Operating lease ROU assets and operating lease liabilities are recognized at commencement date of an arrangement based on the present value of lease payments over the lease term and amortized on a straight-line basis over the lease term. The ROU asset reflected in *"Other assets, net"* above is related to the Company's corporate office lease. See Note 2, *"Leases"* for additional information.

(4) Accrued royalties payable for the year ended June 30, 2022 related to royalty and owner payments in the Jonah Field as the Company takes its natural gas and NGL working interest production in-kind. See Note 3, *"Revenue Recognition"* for a further discussion.

Note 15. Subsequent Events

On September 12, 2022, the Company declared a quarterly cash dividend of $0.12 per share of common stock to shareholders of record on September 21, 2022 and payable on September 30, 2022.

On September 8, 2022, the Company's Board of Directors authorized a share repurchase program, under which the Company is approved to repurchase up to $25 million of its common stock through December 31, 2024. The Company intends to fund repurchases from working capital and cash provided by operating activities. As the Company continues to focus on its goal of maximizing total shareholder return, the Board of Directors along with the management team believe that a share repurchase program is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will depend on a variety of factors, including management’s assessment of the intrinsic value of the Company’s shares, the market price of the Company's common stock, general market and economic conditions, and applicable legal requirements. The value of shares authorized for repurchase by the Company's Board of Directors does not require the Company to repurchase such shares or guarantee that such shares will be repurchased, and the program may be suspended, modified, or discontinued at any time without prior notice.

Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)

Capitalized costs relating to oil and natural gas producing activities

The following table summarizes the amounts of capitalized costs relating to oil and natural gas producing activities and the amount of related accumulated depletion (in thousands).

	June 30, 2022	June 30, 2021	June 30, 2020
Oil and natural gas properties			
Property costs subject to amortization	$ 188,634	$ 129,123	$ 107,390
Less: Accumulated depletion, depreciation, and amortization	(78,126)	(70,607)	(40,878)
Oil and natural gas properties, net	$ 110,508	$ 58,516	$ 66,512

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 (in thousands). 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, geologic 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. Development costs also include amounts incurred due to the recognition of asset retirement obligations of $7.8 million, $2.9 million, and $0.9 million during the years ended June 30, 2022, 2021, and 2020, respectively.

	For the Years Ended June 30,		
	2022	2021	2020
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$ 49,920	$ 18,297	$ 9,338
Unproved property	—	—	—
Exploration costs	—	—	—
Development costs	9,591	3,436	2,430
Total costs incurred for oil and natural gas activities	$ 59,511	$ 21,733	$ 11,768

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of net proved oil and natural gas reserves of the Company's oil and natural gas properties located entirely within the United States are based on evaluations prepared by third-party reservoir engineers, DeGolyer & MacNaughton ("D&M") and Netherland, Sewell & Associates, Inc. ("NSAI"). Reserve volumes and values were determined under the method prescribed by the SEC for the fiscal years ended June 30, 2022, 2021 and 2020. SEC methodology requires the application of the previous 12-month 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.

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 internal reserve engineering team, which includes third-party consultants. Our internal reserve engineering team and third-party consultants have a combined experience of over 80 years in Petroleum Engineering. The person responsible for overseeing the preparation of our reserves estimates has a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, is a registered Professional Engineer in the State of Texas, has over 40 years of oil and natural gas experience including large independents and financial firm services for projects and acquisitions. Our Board of Directors also has oversight of our reserve estimation process and contains an independent director who is a Register Professional Engineer with experience in energy company reserve evaluations. Such reserve estimates comply with generally accepted petroleum engineering and evaluation principles, definitions, and guidelines as established by the SEC.

The person responsible for the preparation of the reserve report at D&M is Dilhan Ilk, Senior Vice President and Division Manager of North America. Dr. Ilk received a Bachelor of Science degree in Petroleum Engineering in 2003 from Istanbul Technical University and a Master's degree and Doctorate in Petroleum Engineering in 2005 and 2010, respectively, from Texas A&M University, and he has in excess of 10 years of experience in oil and natural gas reservoir studies and evaluations. The person responsible for the preparation of the reserve report at NSAI is Steven W. Jansen, P.E., Vice President. Mr. Jansen, a Licensed Professional Engineer in the State of Texas (No. 112973), has been practicing consulting petroleum engineering at NSAI since 2011 and has over four years of prior industry experience. He graduated from Kansas State University in 2007 with a Bachelor of Science Degree in Chemical Engineering.

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

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

	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBOE)
Proved developed and undeveloped reserves:				
June 30, 2019	7,616	—	1,365	8,981
Revisions of previous estimates	(2,179)	—	734	(1,445)
Purchase of reserves in place	3,427	—	—	3,427
Production (sales volumes)	(638)	—	(106)	(744)
June 30, 2020	8,226	—	1,993	10,219
Revisions of previous estimates	662	—	92	754
Purchase of reserves in place	87	49,534	4,957	13,300
Production (sales volumes)	(555)	(963)	(171)	(887)
June 30, 2021	8,420	48,571	6,871	23,386
Revisions of previous estimates	(1,111)	25,268	(944)	2,157
Improved recovery, extensions and discoveries	2,608	2,197	623	3,597
Purchase of reserves in place	2,172	38,096	755	9,276
Production (sales volumes)	(619)	(7,141)	(364)	(2,173)
June 30, 2022	11,470	106,991	6,941	36,243

	MBOE		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Proved developed and undeveloped reserves:			
June 30, 2019	7,399	1,582	8,981
Revisions of previous estimates	(1,727)	282	(1,445)
Purchase of reserves in place	3,427	—	3,427
Production (sales volumes)	(744)	—	(744)
June 30, 2020	8,355	1,864	10,219
Revisions of previous estimates	805	(51)	754
Purchase of reserves in place	13,300	—	13,300
Production (sales volumes)	(887)	—	(887)
June 30, 2021	21,573	1,813	23,386
Revisions of previous estimates	3,970	(1,813)	2,157
Improved recovery, extensions and discoveries	—	3,597	3,597
Purchase of reserves in place	9,276	—	9,276
Production (sales volumes)	(2,173)	—	(2,173)
June 30, 2022	32,646	3,597	36,243

For the fiscal year ended June 30, 2022, notable changes in total proved reserves included the following:

- *Purchase of reserves in place*. During the fiscal year ended 2022, the Company completed the Williston Basin Acquisition and the Jonah Field Acquisition. See Note 4, "*Acquisitions*" for more details.
- *Improved recovery, extensions and discoveries*. During the fiscal year 2022, the Company added 3.6 MBOE of PUD reserves associated with drilling locations at its Willison Basin properties.
- *Revisions of previous estimates.* Net Revisions in fiscal year 2022 totaled 2.2 MMBOE, which included a net positive revision in the Company's proved developed reserves of 4.0 MMBOE offset by the removal of 1.8 MMBOE of PUD reserves at the Delhi Field, related to Test Site V. At this time, the operator at Delhi does not currently have Test Site V on its expenditure schedule for the next five years and, as a result, has been excluded from the Company's PUD reserves. The net positive revision in the Company's proved developed reserves of 4.0 MMBOE includes positive revisions totaling 4.7 MMBOE primarily related to the improvement in the SEC trailing 12-month pricing offset by a 0.7 MMBOE downward adjustment at Delhi due to lower than anticipated production during fiscal year 2022.

For the fiscal year ended June 30, 2021, notable changes in total proved reserves included the following:

- *Purchase of reserves in place*. During the fiscal year ended 2021, the Company completed the Barnett Shale Acquisition. See Note 4, "*Acquisitions*" for more details.
- *Revisions of previous estimates*. Revisions in fiscal year 2021 were primarily due to positive revisions at Hamilton Dome Field reflecting the impact of increased oil pricing in the field on future production and extension of reserves economic limit. Positive NGL revisions at Delhi Field reflect the impact of increased pricing on future production and the extension of reserves economic limit. Positive natural gas revisions in the Barnett Shale properties reflect the impact of increased natural gas prices from the date of the Barnett Shale Acquisition on May 7, 2021 to the end of the fiscal year on June 30, 2021.

For the fiscal year ended June 30, 2020, notable changes in total proved reserves included the following:

- *Purchase of reserves in place*. During the fiscal year ended 2020, the Company acquired certain mineral interest in the Hamilton Dome Field.
- *Revisions of previous estimates.* Revisions in fiscal year 2020 were primarily due to negative revisions at Hamilton Dome Field reflecting the impact of lower pricing on future economic production. In March 2020, the operator began to shut-in wells that were not economic at lower prices. The use of an SEC price deck for 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 the Company's independent reservoir engineering firm.

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 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 related to proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company's proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of the Company's proved reserves.

The Standardized Measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2022, 2021 and 2020 are as follows (in thousands):

	For the Years Ended June 30,		
	2022	2021	2020
Future cash inflows	$ 1,846,708	$ 632,620	$ 399,358
Future production costs and severance taxes	(997,362)	(398,022)	(240,400)
Future development costs	(105,966)	(29,339)	(24,623)
Future income tax expenses	(159,912)	(42,368)	(21,982)
Future net cash flows	583,468	162,891	112,353
10% annual discount for estimated timing of cash flows	(268,685)	(75,308)	(49,862)
Standardized measure of discounted future net cash flows	$ 314,783	$ 87,583	$ 62,491

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12-month 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,		
NYMEX prices used in determining future cash flows:	2022	2021	2020
Oil (Bbl)	$ 85.82	$ 49.72	$ 47.37
Gas (MMBtu)	$ 5.19	$ 2.46	n/a

The NGL prices utilized for future cash inflows were based on historical prices received, where available.

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

	For the Years Ended June 30,		
	2022	2021	2020
Balance, beginning of year	$ 87,583	$ 62,491	$ 126,732
Net changes in sales prices and production costs related to future production	171,602	11,538	(83,857)
Changes in estimated future development costs	(6,320)	403	(4,100)
Sales of oil and gas produced during the period, net of production costs	(60,269)	(16,115)	(16,094)
Net change due to extensions, discoveries, and improved recovery	43,495	—	—
Net change due to revisions in quantity estimates	48,177	6,841	(6,746)
Net change due to purchase of minerals in place	100,675	31,461	10,365
Development costs incurred during the period	—	—	1,431
Accretion of discount	14,425	7,529	16,267
Net change in discounted income taxes	(65,559)	(10,678)	17,079
Other	(19,026)	(5,887)	1,414
Balance, end of year	$ 314,783	$ 87,583	$ 62,491

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 our management, including our Principal Executive Officer and Principal 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 our management, including our Principal Executive Officer and Principal 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 Principal Executive Officer and Principal 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

Our 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, our principal executive and principal financial officers and effected by our 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 Principal Executive Officer and the Principal Financial Officer, an evaluation was conducted on the effectiveness of our 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 we maintained effective internal control over financial reporting as of June 30, 2022.

Effective April 27, 2020, the Securities and Exchange Commission 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 as of June 30, 2022 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 our internal control over financial reporting during the three months ended June 30, 2022 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure regarding foreign jurisdictions that prevent inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2022 fiscal year.

Item 11. Executive Compensation

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2022 fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2022 fiscal year.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2022 fiscal year.

Item 14. Principal Accountant Fees and Services

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2022 fiscal year.

PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. **Financial Statements.**

   The consolidated financial statements of the Company and its subsidiaries are included in Part II, Item 8 of this report:

   Report of Independent Registered Public Accounting Firm
   Consolidated Balance Sheets
   Consolidated Statements of Operations
   Consolidated Statements of Cash Flows
   Consolidated Statements of Changes in Stockholders’ Equity
   Notes to the Consolidated Financial Statements
   Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)

2. **Financial Statements Schedules and Supplementary Information Required to be Submitted:**

   None.

3. **Exhibits**

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

Item 16. Form 10-K Summary

None.

EXHIBIT INDEX

EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
3.1	Articles of Incorporation (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed February 7, 2002)
3.2	Certificate of Amendment to Articles of Incorporation (incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed February 7, 2002)
3.3	Certificate of Amendment to Articles of Incorporation (incorporated by reference to Exhibit 3.3 of our Registration Statement on Form SB-2/A filed October 19, 2005)
3.4	Certificate of Designation of Rights and Preferences for 8.5% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed June 29, 2011)
3.5	Amended Bylaws (incorporated by reference to Exhibit 2.1 of our Annual Report on Form 10-KSB filed March 31, 2004)
4.1	Description of Evolution Petroleum Corporations, securities registered under Section 12 of the Exchange Act (incorporated by reference to our Registration of Securities on Form 8-A filed July 13, 2006)
4.1.1	Specimen form of the Company's Common Stock Certificate (incorporated by reference to Exhibit 4.7 of our Registration Statement on Form S-3 filed June 19, 2013)
4.2	Majority Voting Policy for Directors (incorporated by reference to Exhibit 99.1 of our Current Report on Form 8-K filed October 31, 2012)
4.3†	2016 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed February 8, 2017)
4.4†	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan (incorporated by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q filed February 8, 2018)
4.4.1†	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (incorporated by reference to Exhibit 4.12 of our Annual Report on Form 10-K filed September 13, 2019)
4.5†	Form of Contingent Restricted Stock Agreement under 2016 Equity Incentive Plan (incorporated by reference to Exhibit 4.2 of our Quarterly Report on Form 10-Q filed February 8, 2018)
4.6†	Form of Performance Share Unit Award Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (incorporated by reference to Exhibit 4.13 of our Annual Report on Form 10-K filed September 13, 2019)
10.1	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed September 22, 2006)
10.2	Credit Agreement dated April 11, 2016 between Evolution Petroleum Corporation and MidFirst Bank (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed April 15, 2016)
10.2.1	First Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective October 18, 2016 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed November 9, 2016)
10.2.2	Second Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective February 1, 2018 (incorporated by reference to exhibit 10.1 of our Quarterly Report on Form 10-Q filed February 8, 2018)
10.2.3	Third Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective May 25, 2018 (incorporated by reference to Exhibit 10.10 of our Annual Report on Form 10-K filed September 10, 2018)
10.2.4	Fourth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective December 31, 2018 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed February 8, 2019)

EXHIBIT NUMBER	DESCRIPTION
10.2.5	Fifth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective November 2, 2020 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed November 9, 2020)
10.2.6	Sixth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective December 28, 2020 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on January 11, 2021)
10.2.7	Seventh Amendment to Credit Agreement dated August 5, 2021, between Evolution Petroleum Corporation and MidFirst Bank effective June 30, 2021 (incorporated by reference to Exhibit 10.8 of our Quarterly Report on Form 10-Q filed May 12, 2022)
10.2.8	Eighth Amendment to Credit Agreement dated November 9, 2021, between Evolution Petroleum Corporation and MidFirst Bank effective November 9, 2021 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed November 10, 2021)
10.2.9	Ninth Amendment to the Credit Agreement dated February 7, 2022, between Evolution Petroleum Corporation and MidFirst Bank effective February 4, 2022 (incorporated by reference to Exhibit 10.9 of our Quarterly Report on Form 10-Q filed May 12, 2022)
10.3	Settlement Agreement, dated June 24, 2016, by and among Denbury Onshore, LLC, Denbury Inc., NGS Sub Corp., Tertiaire Resources Company, and the Company (incorporated by reference to Exhibit 10.7 of our Annual Report on Form 10-K filed September 9, 2016)
10.4†	Employment Offer Letter to Jason E. Brown dated July 8, 2019 (incorporated by reference to Exhibit 10.12 of our Annual Report on Form 10-K filed September 13, 2019)
10.5†	Employment Offer Letter to Ryan Stash dated October 9, 2020 (incorporated by reference to Exhibit 10.1 of our Annual Report on Form 10-K filed September 14, 2021)
10.6	Purchase and Sale Agreement, dated March 29, 2021, between Evolution Petroleum Corporation and TG Barnett Resources LLP (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on May 11, 2021)
10.6.1	First Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective April 20, 2021 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on May 11, 2021)
10.6.2	Second Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective May 4, 2021 (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed on May 11, 2021)
10.6.3	Third Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective May 6, 2021 (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed on May 11, 2021)
10.7	Purchase and Sale Agreement, dated January 14, 2022, between Evolution Petroleum Corporation, Foundation Energy Fund VII-A, LP and Foundation Energy Management, LLC (incorporated by reference to Exhibit 10.6 our Quarterly Report on Form 10-Q filed May 12, 2022)
10.8	Purchase and Sale Agreement, dated April 1, 2022, between Evolution Petroleum Corporation and Exaro Energy III, LL (incorporated by reference to Exhibit 10.7 of our Quarterly Report on Form 10-Q filed May 12, 2022)
14.1	Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 of our Annual Report on Form 10-K filed September 14, 2021)
21.1*	List of Subsidiaries of Evolution Petroleum Corporation
23.1*	Consent of Moss Adams LLP
23.2*	Consent of DeGolyer & MacNaughton
23.3*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Principal 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
31.2*	Certification of Principal 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
32.1**	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

EXHIBIT NUMBER	DESCRIPTION
32.2**	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	The summary of DeGolyer and MacNaughton's Report as of June 30, 2022, on oil and gas reserves (SEC Case) dated August 4, 2022 and certificate of qualification
99.2*	The summary of Netherland, Sewell & Associates, Inc.'s Report as of June 30, 2022, on oil and gas reserves (SEC Case) dated August 9, 2022 and certificate of qualification
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document)

** Attached hereto.*

*** Furnished herewith.*

† Indicates management contract or compensatory plan or arrangement

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 14, 2022	By: /s/ KELLY W. LOYD
	Kelly W. Loyd
	Interim President and Chief Executive Officer (Principal Executive Officer) and Director

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 14, 2022	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 14, 2022	/s/ KELLY W. LOYD Kelly W. Loyd	Interim President and Chief Executive Officer (Principal Executive Officer) and Director
September 14, 2022	/s/ RYAN STASH Ryan Stash	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer and Principal Accounting Officer)
September 14, 2022	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 14, 2022	/s/ MYRA C. BIERRIA Myra C. Bierria	Director
September 14, 2022	/s/ WILLIAM DOZIER William Dozier	Director
September 14, 2022	/s/ MARJORIE A. HARGRAVE Marjorie A. Hargrave	Director

Exhibit 21.1

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 the Registration Statements on Forms S-3 (No. 333-265430 and No. 333-193899), Form S-3/A (No. 333-231412) and Forms S-8 (333-251233, 333-152136, 333-140182, 333-183746 and 333-216098) of Evolution Petroleum Corporation (the "Company"), of our report dated September 14, 2022, relating to the consolidated financial statements of the Company which report expresses an unqualified opinion, appearing in this Annual Report on Form 10-K of the Company for the year ended June 30, 2022.

/s/ Moss Adams LLP

Houston, Texas
September 14, 2022

EXHIBIT 23.2

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

September 14, 2022

Evolution Petroleum Corporation
1155 Dairy Ashford Road, 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 4, 2022, and to the inclusion of information taken from our report entitled "Report as of June 30, 2022 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, 2022. 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. 333-251233, 333-152136, 333-140182, 333-183746, and 333-216098), Form S-3 (File No. 333-265430), 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

NETHERLAND, SEWELL & ASSOCIATES, INC.

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves report dated August 9, 2022, included in the Annual Report on Form 10-K of Evolution Petroleum Corporation (the "Company") for the fiscal year ended June 30, 2022, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves reports into the Registration Statements on Form S-3 No. 333-265430, Form S-3/A No. 333-231412, Form S-3 No. 333-193899, Form S-8 Nos. 333-251233, 333-152136, 333-140182, 333-183746, and 333-216098.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.

Richard B. Talley, Jr., P.E.
Chief Executive Officer

Houston, Texas
September 14, 2022

CERTIFICATION

I, Kelly W. Loyd, Interim President and Chief Executive Officer (Principal Executive Officer) and Director, 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 14, 2022

/s/ KELLY W. LOYD
Kelly W. Loyd
Interim President and Chief Executive Officer (Principal Executive Officer) and Director

EXHIBIT 31.2

CERTIFICATION

I, Ryan Stash, Senior Vice President, Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer) and Treasurer 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 14, 2022

/s/ RYAN STASH

Ryan Stash

Senior Vice President, Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer) and Treasurer

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

The undersigned, Kelly W. Loyd, Interim President and Chief Executive Officer (Principal Executive Officer) and Director 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, 2022 (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 14, 2022.

/s/ KELLY W. LOYD
Kelly W. Loyd
Interim President and Chief Executive Officer (Principal Executive Officer) and Director

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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, Ryan Stash, Senior Vice President, Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer) and Treasurer 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, 2022 (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 14, 2022.

/s/ RYAN STASH
Ryan Stash
Senior Vice President, Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer) and Treasurer

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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

EXHIBIT 99.1

August 4, 2022

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, 2022, of the extent and value of the estimated net proved developed producing oil, condensate, natural gas liquids (NGL), and gas reserves of the Delhi field in Louisiana, the proved developed producing condensate, NGL, and gas reserves of the Barnett Shale in Texas, and the proved developed producing oil reserves of 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. The properties evaluated herein consist of working and royalty interests. This evaluation was completed on August 4, 2022. Evolution has represented that these properties account for greater than 63 percent on a net equivalent barrel basis of Evolution's net proved reserves as of June 30, 2022. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with the guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Evolution.

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, 2022. 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 developed producing 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 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 at mid-year on an annual basis 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 developed producing. Only proved developed producing 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” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. 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 and production performance, reserves were classified as proved developed producing.

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.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior.

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

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, 2022, 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, 2022. Cumulative production, as of June 30, 2022, was deducted from the estimated gross ultimate recovery to estimate gross reserves.

Oil and condensate 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, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

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 quantities are located. Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

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 include both associated and nonassociated 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, Condensate, and NGL Prices

Evolution has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Evolution to the West Texas Intermediate (WTI) reference price of $85.82 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $80.53 per barrel of oil and condensate and $45.00 per barrel of NGL.

Gas Prices

Evolution has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Evolution supplied differentials to the Henry Hub gas reference price of $5.19 per million Btu. The prices were held constant thereafter. Btu factors were provided by Evolution and used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $5.292 per thousand cubic feet of gas.

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 values from the 12 months prior to the as-of date of this report, 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.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved developed producing reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, and 1202(a) (1), (2), (3), (4), (8) 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 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

DeGolyer and MacNaughton has performed an independent evaluation of the extent and value of the estimated net proved developed producing oil, condensate, NGL, and gas reserves of certain properties in which Evolution has represented it holds an interest.

The estimated net proved reserves, as of June 30, 2022, of the properties evaluated herein were based on the definition of proved developed producing 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, 2022		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved Developed Producing	6,629	5,445	65,618

The estimated future revenue to be derived from the production and sale of the net proved developed producing reserves, as of June 30, 2022, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing (M$)
Future Gross Revenue	1,126,121
Production Taxes	45,226
Ad Valorem Taxes	38,889
Operating Expenses	615,474
Capital Costs	6,340
Abandonment Costs	23,200
Future Net Revenue	396,992
Present Worth at 10 Percent	219,652

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, 2022, 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/ Dilhan Ilk

[Seal]

Dilhan Ilk, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

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

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare this report of third party addressed to Evolution dated
August 4, 2022, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 11 years of experience in oil and gas reservoir studies and reserves evaluations.

s/ Dilhan Ilk

[Seal]

Dilhan Ilk, P.E.
Senior Vice President
DeGolyer and MacNaughton

EXHIBIT 99.2

August 9, 2022

Mr. Kelly W. Loyd
Evolution Petroleum Corporation
1155 Dairy Ashford Street, Suite 425
Houston, Texas 77079

Dear Mr. Loyd:

In accordance with your request, we have estimated the proved reserves and future revenue, as of June 30, 2022, to the Evolution Petroleum Corporation (Evolution) interest in certain oil and gas properties located in North Dakota and Wyoming, referred to herein as the Jonah and Williston Assets. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 37 percent of all proved reserves owned by Evolution. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Evolution's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Evolution interest in the Jonah and Williston Assets, as of June 30, 2022, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	2,075.5	854.0	39,104.3	227,194.5	138,170.9
Proved Developed Non-Producing	157.2	18.8	70.8	7,080.8	2,504.2
Proved Undeveloped	2,608.1	622.8	2,197.0	112,113.3	43,494.8
Total Proved	4,840.8	1,495.6	41,372.1	346,388.5	184,169.9

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Evolution's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Evolution's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period July 2021 through June 2022. For oil and NGL volumes, the average West Texas Intermediate spot price of $85.82 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $5.19 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $82.70 per barrel of oil, $41.45 per barrel of NGL, and $6.24 per MCF of gas.

Operating costs used in this report are based on operating expense records of Evolution. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Evolution and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Evolution's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Evolution interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Evolution receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Evolution, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Evolution, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Steven W. Jansen, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 4 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees II
C.H. (Scott) Rees III, P.E.
Executive Chairman

By: /s/ Steven W. Jansen
Steven W. Jansen, P.E. 112973
Vice President

Date Signed: August 9, 2022

SWJ:MJM

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *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.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

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

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

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

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

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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

    (A) Costs of labor to operate the wells and related equipment and facilities.
    (B) Repairs and maintenance.
    (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
    (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
    (E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *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:

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(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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

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(31) *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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.