UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2022.

OR

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

Commission file number 001-38770

EPSILON ENERGY LTD.
(Exact name of registrant as specified in its charter)

Alberta, Canada	**98-1476367**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

500 Dallas Street, Suite 1250
Houston, Texas 77002
(281) 670-0002
(Address of principal executive offices including zip code and telephone number, including area code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Shares, no par value	EPSN	NASDAQ Global Market

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 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, a smaller reporting company or an emerging growth company. See the definitions 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. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to § 240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $80.2 million. There were 22,926,444 Common Shares (no par value) outstanding as of March 22, 2023.

PART I

FORWARD LOOKING STATEMENTS.

Certain statements contained in this report constitute forward-looking statements. The use of any of the words ''anticipate,'' ''continue,'' ''estimate,'' ''expect,'' ''may,'' ''will,'' ''project,'' ''should,'' ''believe,'' and similar expressions and statements relating to matters that are not historical facts constitute ''forward looking statements'' within the meaning of applicable securities laws. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated. Such forward-looking statements are based on reasonable assumptions, but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this report should not be unduly relied upon. These statements are made only as of the date of this report. All statements that address operating performance, events or developments that we expect or anticipate will occur in the future — including statements relating to oil and natural gas production rates, commodity prices for crude oil or natural gas, supply and demand for oil and natural gas; the estimated quantity of oil and natural gas reserves, including reserve life; future development and production costs, and statements expressing general views about future operating results — are forward-looking statements. Management believes that these forward-looking statements are reasonable as and when made. However, caution should be taken not to place undue reliance on any such forward-looking statements because such statements speak only as of the date when made. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. In addition, forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from our present expectations or projections. These risks and uncertainties include, but are not limited to, those described in this Annual Report on Form 10-K, and those described from time to time in our future reports filed with the Securities and Exchange Commission.

DEFINED TERMS

We have included below the definitions for certain terms used in this document:

''3-D seismic'' Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

''ABCA'' Business Corporations Act (Alberta).

''Anchor shippers'' Parties listed in the Anchor Shipper Gas Gathering Agreement for Northern Pennsylvania, including Epsilon Energy USA, Inc., Equinor USA Onshore Properties, Inc., and Chesapeake Energy Corporation. for the Auburn Gas Gathering System.

''ASC'' Accounting Standards Codification.

''Bbl'' One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

''Bcf'' One billion cubic feet, used in reference to natural gas.

''BOE'' One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

''Completion'' The process of preparing a natural gas and oil wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

''Delay rental'' Consideration paid to the lessor by a lessee to extend the terms of an oil and natural gas lease in the absence of drilling operations and/or production that is contractually required to hold the lease. This consideration is generally required to be paid on or before the anniversary date of the natural gas and oil lease during its primary term, and typically extends the lease for an additional year.

''Development well'' A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

''Differential'' The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

''Dry hole'' A well found to be incapable of producing either natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

''Exit rate'' Upstream term referring to the rate of production of oil and/or gas as of a specified date.

''Exploratory well'' 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 natural gas in another reservoir.

''FASB'' Financial Accounting Standards Board.

''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 that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or 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.

''Free cash flow'' A measure of a company's financial performance, calculated as operating cash flow minus capital expenditures. Free cash flow represents the cash that a company is able to generate after spending the money required to maintain or expand its asset base.

''GAAP'' Generally accepted accounting principles in the United States of America.

''Gross acres'' or *''gross wells''* The total acres or wells, as the case may be, in which a working interest is owned.

"*Henry Hub"* A natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the NYMEX. The hub is owned by Sabine Pipe Line LLC and has access to many of the major gas markets in the United States.

''ISDA'' International Swaps and Derivatives Association, Inc.

''Lease operating expense'' or ''LOE'' The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

''LIBOR'' London interbank offered rate.

''MBbl'' One thousand barrels of oil, NGLs or other liquid hydrocarbons.

''MBbl/d'' One MBbl per day.

''MBOE'' One thousand BOE.

''MBOE/d'' One MBOE per day.

''Mcf'' One thousand cubic feet, used in reference to natural gas.

''MMBbl'' One million Bbl.

''MMBOE'' One million BOE.

''MMBtu'' One million British Thermal Units, used in reference to natural gas.

''MMcf'' One million cubic feet, used in reference to natural gas.

''MMcf/d'' One MMcf per day.

''Net acres'' or *''net wells''* The sum of the fractional working interests owned in gross acres or wells, as the case may be.

''Net production'' The total production attributable to the fractional working interest owned.

''NGL'' Natural gas liquid.

''NYMEX'' The New York Mercantile Exchange. ''PDNP'' Proved developed nonproducing reserves. ''PDP'' Proved developed producing reserves.

''Plugging and abandonment'' Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

''Prospect'' A property on which indications of oil or gas have been identified based on available seismic and geological information.

''Proved developed reserves'' Proved reserves that can be expected to be recovered 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.

''Proved reserves'' Those reserves that, 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.

The area of the reservoir considered as proved includes all of the following:

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.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

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.

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 before 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.

''Proved undeveloped reserves'' or *''PUDs''* 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. 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. 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 specific circumstances justify a longer time. Under no circumstances shall estimates of proved 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.

''PV-10'' 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.

''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 percent 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 with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

''Reserves'' Estimated remaining quantities of natural gas and oil 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 natural gas and oil or related substances to market, and all permits and financing required to implement the project.

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

''Royalty'' The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

''Royalty interest'' An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

''Section'' An area of one square mile of land, 640 acres, with 36 sections making up one survey township on a rectangular grid.

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

''Working interest'' The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

''Workover'' Operations on a producing well to restore or increase production.

ITEM 1. BUSINESS.

Summary

Epsilon Energy Ltd. (the "Company" or "Epsilon" or "we") was incorporated under the laws of the Province of Alberta, Canada on March 14, 2005, pursuant to the ABCA. The Company is extra-provincially registered in Ontario pursuant to the *Business Corporations Act* (Ontario). Epsilon is a North American on-shore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves. On October 24, 2007, the Company became a publicly traded entity trading on the Toronto Stock Exchange ("TSX") in Canada. On February 14, 2019, Epsilon's registration statement on Form 10 was declared effective by the United States Securities and Exchange Commission and on February 19, 2019, we began trading in the United States on the NASDAQ Global Market under the trading symbol "EPSN." Effective as of the close of trading on March 15, 2019, Epsilon voluntarily delisted its common shares from the TSX. At December 31, 2022, Epsilon's total estimated net proved reserves were 90,040 million cubic feet of natural gas reserves, 491,226 barrels of NGL reserves, and 211,059 barrels of oil and other liquids. Epsilon holds leasehold rights to approximately 75,954 gross (13,625 net) acres. The Company has natural gas production in the Marcellus Shale in Pennsylvania and oil, natural gas liquids and natural gas production in the Anadarko Basin in Oklahoma.

We conduct operations in the United States through our wholly owned subsidiaries Epsilon Energy USA Inc., an Ohio corporation, or Epsilon Energy USA; Epsilon Midstream, LLC, a Pennsylvania limited liability company, or Epsilon Midstream; Epsilon Operating, LLC, a Delaware limited liability company, Dewey Energy GP LLC, a Delaware limited liability company, Dewey Energy Holdings LLC, a Delaware limited liability company, and Altolisa Holdings, LLC, a Delaware limited liability company.

Substantially all the production from our Pennsylvania acreage (5,098 net) is dedicated to the Auburn Gas Gathering System, or the Auburn GGS, located in Susquehanna County, Pennsylvania for a 15-year term expiring in 2026 under an operating agreement whereby the Auburn GGS owners receive a fixed percentage rate of return on the total capital invested in the construction and maintenance of the system. We own a 35% interest in the Auburn GGS which is operated by a subsidiary of Williams Partners, LP. In 2022, we paid $1.5 million to the Auburn GGS to gather and treat our 9.0 Bcf of natural gas production in Pennsylvania ($1.6 million was paid to the Auburn GGS to gather and treat our 9.8 Bcf in 2021).

Our principal executive office is located at 500 Dallas Street, Suite 1250, Houston, Texas 77002, and our telephone number at that address is (281) 670-0002. Our registered office in Alberta, Canada is located at 14505 Bannister Road SE, Suite 300, Calgary, AB, Canada T2X 3J3.

Business highlights of 2022

Operational Highlights

Marcellus Shale—Pennsylvania

- During the year ended December 31, 2022, Epsilon's realized natural gas price was $5.96 per Mcf, a 96% increase from $3.04 for the year ended December 31, 2021.
- Total year ended December 31, 2022 natural gas production was 9.0 Bcf, as compared to 9.8 Bcf during 2021.
- Gathered and delivered 66.3 Bcf gross (23.2 Bcf net to Epsilon's interest) during the year, or 182 MMcf/d through the Auburn GGS.
- We participated in the drilling of 5 gross (0.05 net) and completion of 4 gross (0.21 net) Marcellus wells in 2022. These wells went into production at various times in August and September.
- At year end, the Company had 2 gross (0.02 net) wells waiting on completion.

Anadarko, NW STACK Trend—Oklahoma

- During the year ended December 31, 2022, Epsilon's realized price for all Oklahoma production was $8.68 per Mcfe, a 37% increase from $6.34 for the year ended December 31, 2021.
- Total production for 2022 included natural gas, oil, and other liquids and was 0.93 Bcfe, as compared to 0.73 Bcfe during 2021.
- In 2022, the Company participated in the drilling of 2 gross (0.26 net) wells and completion of 3 gross (0.70 net) wells.
- At year end, the Company had 1 gross (0.11 net) well waiting on completion.

Properties

As of December 31, 2022, Epsilon's 75,954 gross (13,625 net) acres are all located in the United States and include 351 gross (36.33 net) wells.

	Gross[(1)]	**Net**[(2)]
Producing Wells		
Gas	283	31.18
Oil	27	2.18
Total Producing Wells	310	33.36
Non-Producing Wells	41	2.97
Total Wells	351	36.33

Acreage

As of December 31, 2022, our leasehold inventory consisted of the following acreage amounts, rounded to the nearest acre:

	Gross[(1)]	**Net**[(2) (3)]
Developed Acres		
Pennsylvania	12,963	4,763
Oklahoma	7,063	2,290
	20,026	7,053
Undeveloped Acres		
Pennsylvania	335	335
Oklahoma	55,593	6,237
	55,928	6,572
Total Acres		
Pennsylvania	13,298	5,098
Oklahoma	62,656	8,527
Total acres	75,954	13,625

(1) "Gross" means one-hundred percent of the working interest ownership in each leasehold tract of land.

(2) "Net" means the Company's fractional working interest share in each leasehold tract of land on which productive wells have been drilled.

(3) "Net Undeveloped" means the Company's fractional working interest share in each leasehold tract of land where productive wells have yet to be drilled. All of Epsilon's Oklahoma undeveloped properties are deep rights acreage which is held by production of developed properties.

Business Segments

Our operations are conducted by three operating segments for which information is provided in our consolidated financial statements for the years ended December 31, 2022 and 2021.

The three segments are as follows:

Upstream: Activities include acquisition, exploration, development and production of oil and natural gas reserves on properties within the United States.

Gathering System: We partner with two other companies to operate a natural gas gathering system.

Corporate: Activities include our corporate and governance functions.

For information about our segment's revenues, profits and losses, total assets, and total liabilities, see Note 12 Operating Segments in the Notes to Consolidated Financial Statements.

Oil and Natural Gas Production and Revenues and Gathering System Revenues

A summary of our net oil and natural gas production, average oil and natural gas prices and related revenues and our gathering system revenues for the years ended December 31, 2022 and 2021, respectively, follows:

	Year ended December 31, 2022	2021
Production Volumes		
Pennsylvania		
Natural gas (MMcf)	9,026	9,830
Total (Mmcfe)	**9,026**	**9,830**
Oklahoma		
Natural gas (MMcf)	477	403
Natural gas liquids (MBbl)	44	29
Oil & other liquids (MBbl)	32	25
Total (Mmcfe)	**935**	**727**
Company Total		
Natural gas (MMcf)	9,503	10,233
Natural gas liquids (MBbl)	44	29
Oil & other liquids (MBbl)	32	25
Total (Mmcfe)	**9,961**	**10,557**

	Year ended December 31, 2022	2021
Revenues		
Pennsylvania		
Natural gas revenue	**$ 53,759,354**	**$ 29,909,651**
Avg. Price ($/Mcf)	$ 5.96	$ 3.04
Gathering system revenue	**$ 8,085,512**	**$ 7,865,825**
Total PA Revenues	**$ 61,844,866**	**$ 37,775,476**
Oklahoma		
Natural gas revenue	**$ 3,189,380**	**$ 1,798,534**
Avg. Price ($/Mcf)	$ 6.68	$ 4.46
Natural liquids revenue	**$ 1,733,129**	**$ 1,053,486**
Avg. Price ($/Bbl)	$ 39.31	$ 35.98
Oil and condensate revenue	**$ 3,195,334**	**$ 1,776,496**
Avg. Price ($/Bbl)	$ 99.24	$ 70.70
Total OK Revenues	**$ 8,117,843**	**$ 4,628,516**
Total Company Revenues	**$ 69,962,709**	**$ 42,403,992**

Gathering System Operations

Epsilon Energy USA is the 100% owner of Epsilon Midstream, which owns a 35% undivided interest in the Auburn GGS, located in Susquehanna County, Pennsylvania, with partners Appalachia Midstream Services, LLC (43.875%) and Equinor Pipelines, LLC (21.125%). The Anchor Shippers, consisting of Epsilon Energy USA, Equinor USA Onshore Properties, Inc., and Chesapeake Energy Corporation, dedicated approximately 18,000 mineral acres to the Auburn GGS for an initial term of 15 years under an operating agreement whereby the Auburn GGS owners receive a fixed percentage rate of return on the total capital invested in the construction of the system.

The gathering rate of the Auburn GGS is determined by a cost of service model whereby the Anchor Shippers dedicate acreage and reserves to the gas gathering system in exchange for the Auburn GGS owners agreeing to an 18% contractual rate of return on invested capital. The term of this arrangement is 15 years commencing January 1, 2012 and expiring December 31, 2026. Each year, the Auburn GGS historical and forecast throughput, revenue, operating expenses and capital expenditures are entered into the cost of service model. The model then computes the new gathering rate that will yield the contractual rate of return to the Auburn GGS owners. In January 2027, the Auburn GGS will transition to a fixed gathering rate.

Revenues from the Auburn GGS are earned primarily from the Anchor Shippers. Revenues are also earned from third-party customers of the system to transport gas from the wellhead to the compression facility, and then to the delivery meter at Tennessee Gas Pipeline. The relative mix of Anchor Shipper gas and third-party gas is critical to the revenue and earnings of the Auburn GGS because the third-party gathering rate is only 25% of the Anchor Shipper rate. Third-party shippers must pay the gathering rate of the originating gathering system plus 25% of the Auburn GGS gathering rate. The purpose of the reduced rate is to attract additional volumes that require delivery to Tennessee Gas Pipeline when there is spare capacity at the Auburn compression facility, or the “Auburn CF”. Throughput at the Auburn CF has declined from 100.1 Bcf in 2018 to 66.3 Bcf in 2022, a decrease of 34%. However, Anchor Shipper gas as a percentage of total throughput has increased from 57% in 2018 to 71% in 2022. As a result of this shift toward a higher percentage of Anchor Shipper gas, revenues and earnings for the gathering system have only declined 21% and 15%, respectively, from 2018 to 2022.

The Auburn GGS consists of approximately 44 miles of gathering pipelines, a small auxiliary compression facility and a main compression facility with three dehydration units and three Caterpillar 3612 compression units. At inception, the capacity of the Auburn CF was approximately 330,000 Mcf per day at a design suction pressure of 800 psig. The design suction pressure was subsequently reduced to 550 psig in June 2020 at the request of the Anchor Shippers. This request served to minimize throughput decline during a period of low pricing in which the drilling of new wells was undesirable. Operating at the lower design suction pressure also has the benefit of reducing hydrate occurrences in the system which can pose an operational hazard. The current system capacity of the Auburn CF at this lower design pressure is approximately 220,000 Mcf per day. The facility capacity could be increased again, if required, by either adding compression units or increasing the design suction pressure.

The Auburn CF delivers processed natural gas into the Tennessee Gas Pipeline at the Shoemaker Dehy receipt meter. The Auburn GGS is connected with the adjacent Rome GGS, which allows for the receipt of additional natural gas to maximize utilization of the Auburn CF and Tennessee Gas Pipeline meter capacity.

During the years ended December 31, 2022 and 2021, the Auburn GGS delivered 66.3 Bcf and 63.2 Bcf respectively, of natural gas, or 182 and 173 MMcf per day.

Revenues derived from Epsilon’s production which have been eliminated from gathering system revenues amounted to $1.5 million and $1.6 million, respectively, for the years ended December 31, 2022 and 2021.

Proved Reserves

Per our reserve report prepared by independent petroleum consultants, DeGolyer and MacNaughton, our estimated proved reserves as of December 31, 2022, are summarized in the table below. See Risk Factors for information relating to the uncertainties surrounding these reserve categories.

	Natural Gas MMcf	Natural Gas Liquids MBbl	Oil and Other Liquids MBbl	Total MMcfe
Proved developed reserves	78,966	198	107	80,795
Proved undeveloped reserves	11,074	293	104	13,459
Total Proved Reserves at December 31, 2022	90,040	491	211	94,254
Changes in Total Proved Undeveloped Reserves				
Proved undeveloped reserves at December 31, 2021	38,743	663	239	44,155
Revisions of previous estimates	(21,598)	(220)	(74)	(23,362)
Extensions and discoveries	—	—	—	—
Transfers to proved developed	(6,071)	(150)	(61)	(7,334)
Proved undeveloped reserves at December 31, 2022	11,074	293	104	13,459

Revisions to previous estimates for total proved undeveloped reserves for 2022 include reductions of 23,505 MMcfe related to changes to the previously adopted development plan, additions of 226 MMcfe related to commodity pricing, and reductions of 83 MMcfe related to well performance. Transfers to proved developed relates to the development of one well in Pennsylvania and three wells in Oklahoma.

We have not engaged in any exploration capital spending in 2022 or 2021. Our development capital spending to convert proved undeveloped reserves to proved developed reserves for the periods indicated is as follows:

- In 2022 in Pennsylvania, 5 gross (0.05 net) wells were drilled and 4 gross (0.21 net) completed. (Net development capital $2.5 million). Reserves of 5.4 Bcf for the 1 well with proved undeveloped reserves were reclassified as proved developed producing as this well was turned online in August 2022. Additionally, 2 gross (0.02 net) wells were drilled in 2022, but not completed (development capital $0.1 million). They were completed and turned online in January 2023.

- In 2021 in Pennsylvania, 3 gross (0.42 net) wells were drilled and 3 gross (0.27 net) completed. (Net development capital $4.1 million). Reserves of 4.6 Bcf for the 3 wells were reclassified as proved developed producing as these wells were turned online at various times beginning in January and going through October of 2021. Additionally, 1 gross (0.18 net) well was drilled in 2021, but not completed (development capital $0.2 million).

- In 2022 in Oklahoma, we drilled 2 gross (0.26 net) wells and completed 3 gross (0.7 net) wells. (Net development capital $5.4 million). Reserves of 2.9 Bcfe for the 3 wells were reclassified as proved developed producing as these wells were tuned online at various times beginning in March 2022 and going through October 2022. One gross (0.11 net) well was drilled in 2022, but not completed. It is scheduled to be completed in April 2023.

- In 2021 in Oklahoma, we drilled 4 gross (0.75 net) wells and completed 2 gross (0.6 net) wells. (Net development capital $3.0 million). Reserves of 2.8 Bcfe were reclassified as proved developed producing.

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 reserve estimates require reserves to be prepared by an independent engineering firm under the supervision of our Chief Operating Officer, and to be in compliance with generally accepted geologic, petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The corporate staff interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting and marketing employees to obtain the necessary data for the reserves estimation process. We provide our engineering firm with property interests, production, capital budgets, current operating costs, current production prices and other information. This information is reviewed by our Chief Operating Officer to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. Reserves are reviewed and approved internally by our Chief Operating Officer on a semi-annual basis. Our Chief Operating Officer holds a Bachelor of Science degree in Petroleum Engineering and received a Master's Degree of Business Administration. He has over 30 years of experience in upstream exploration and production, and has managed all phases of drilling, completions, production and field operations.

The reserve information in this report is based on estimates prepared by DeGolyer and MacNaughton, our independent petroleum consultants. 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 definitions 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 of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

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. These analyses were performed for all well groupings (or type-curve areas).

The person responsible for preparing the reserve report, Dilhan Ilk, is a Registered Professional Engineer (No.139334) in the State of Texas and a Senior Vice President of the firm. Mr. Ilk graduated from Texas A&M University with a Doctor in Philosophy degree in Petroleum Engineering, is a member of the Society of Petroleum Engineers, and has in excess of 11 years of experience in oil and gas reservoir studies and reserves evaluations.

Marketing and Major Customers

Natural gas marketing is competitive in northeast Pennsylvania because of the limited interstate transportation capacity and ample natural gas supply. We do not currently own any firm transportation on interstate pipelines that would enable us to diversify our natural gas sales to downstream customers. As a result, all of our Pennsylvania gas sales occur in Zone 4 of the Tennessee Gas Pipeline at the Shoemaker Dehy meter, which is the receipt point from the Auburn CF.

Epsilon uses a third-party service, ARM Energy Management LLC ("ARM") for its natural gas marketing. In this capacity, ARM is responsible for carrying out marketing activities such as submission of nominations, receipt of payments, submission of invoices and negotiation of contracts.

For the year ended December 31, 2022, we sold natural gas through ARM to 26 unique customers. Direct Energy Business Marketing, LLC and EQT Energy, LLC each accounted for 10% or more of our total revenue. For the year ended December 31, 2021, we sold natural gas through ARM to 30 unique customers. Direct Energy Business Marketing, LLC and SWN Energy Services Company, LLC each accounted for 10% or more of our total revenue.

Geographic Locations of Operations

Approximately 91% and 93% of our production during fiscal 2022 and 2021, respectively, was derived from natural gas production and gathering system revenues in the state of Pennsylvania. Our asset in Pennsylvania has not yet reached the mature stage, but at some point, we may need to acquire and develop other producing assets to maintain our current level or to grow.

As a result of this geographic concentration, we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas.

Competition

It is not uncommon in the oil and natural gas industry to experience shortages of drilling and completion rigs, equipment, pipe, services, and personnel, which can cause both delays in development drilling activities and significant cost increases. We are exposed to the risk of industry competition for drilling rigs, completion rigs and availability of related equipment and services, among other goods and services required in our business.

Our Status as an Emerging Growth Company

We are an "emerging growth company," as defined in the Jumpstart Our Business Startups Act of 2012, or the "JOBS Act". Certain specified reduced reporting and other regulatory requirements are available to public companies that are emerging growth companies. These provisions include:

- an exemption from the auditor attestation requirement in the assessment of our internal controls over financial reporting required by Section 404 of the Sarbanes—Oxley Act of 2002;

- an exemption from the adoption of new or revised financial accounting standards until they would apply to private companies;

- an exemption from compliance with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about our audit and our financial statements; and

- reduced disclosure about our executive compensation arrangements.

We have elected to take advantage of the exemption from the adoption of new or revised financial accounting standards until they would apply to private companies.

We will continue to be an emerging growth company until the earliest of:

- the last day of our fiscal year in which we have total annual gross revenues of $1.235 billion (as such amount is indexed for inflation every five years by the SEC to reflect the change in the Consumer Price Index for All Urban Consumers published by the Bureau of Labor Statistics, setting the threshold to the nearest $1 million) or more;

- the last day of our fiscal year following the fifth anniversary of the date of our first issuance of common equity securities under an effective Securities Act registration statement (December 31, 2019);

- the date on which we have, during the prior three-year period, issued more than $1 billion in non-convertible debt; or

- the date on which we are deemed to be a large accelerated filer under the rules of the SEC, which means the market value of our common shares that is held by non-affiliates (or public float) exceeds $700 million as of the last day of our second fiscal quarter in our prior fiscal year.

Employees

As of December 31, 2022, we had nine full-time employees (including executive officers) in Houston, Texas. None of our employees are subject to a collective bargaining agreement or represented by a union.

The foundation of our Company is our employees and our success begins with a values-driven culture and commitment to developing a skilled, agile, diverse and engaged workforce where every employee understands that they can and do make a difference. Advancing a safe, ethical, inclusive and diverse culture creates an environment that attracts and retains the high-performing workforce needed to successfully execute our strategy.

To build a better tomorrow for everyone, we continue to foster a culture that embraces inclusion and diversity and encourages collaboration. Our core values include inclusion and diversity, and we believe in equity and the value and voice of every employee.

Legal Proceedings

On March 10, 2021, Epsilon filed a complaint against Chesapeake Appalachia, LLC ("Chesapeake") in the United States District Court for the Middle District of Pennsylvania, Scranton, Pennsylvania ("Middle District"). Epsilon claims that Chesapeake has breached a settlement agreement and several operating agreements ("JOAs") to which Epsilon and Chesapeake are parties. Epsilon asserts that Chesapeake has failed to cooperate with Epsilon's efforts to develop resources in the Auburn Development, located in Northeast Pennsylvania, as required under both the settlement agreement and JOAs.

Epsilon requested a preliminary injunction but was unsuccessful in obtaining that injunction. Epsilon filed a motion to amend its original Complaint. Chesapeake opposed. The Court ruled in Epsilon's favor and allowed

Epsilon's amendment. Chesapeake moved to dismiss the amended Complaint. The Court granted the motion to dismiss without prejudice to Epsilon's right to file a new lawsuit based on new proposals made after the Court's decision. Epsilon filed a motion for reconsideration of that decision, but the court denied the motion for reconsideration on January 18, 2022.

Epsilon filed a notice of appeal on February 15, 2022 challenging both the motion to dismiss and motion for reconsideration decisions. Chesapeake filed a cross-appeal on March 1, 2022. A briefing schedule was set and briefing closed October 14, 2022. Oral argument was held in January 2023. A decision on the appeal is not expected until mid-2023.

Epsilon re-filed a complaint against Chesapeake in the Middle District on May 9, 2022. Epsilon generally asserts similar claims as in the previous suit, pursuing declaratory judgment claims regarding Chesapeake's obligation to Epsilon to cooperate with Epsilon's efforts in the Auburn Development and regarding Chesapeake's obstruction of Epsilon's efforts with the Pennsylvania Department of Environmental Protection permitting process but not based on specific well proposals. Chesapeake filed a motion to stay pending a decision on the Third Circuit appeal, which was granted. The matter is stayed pending a decision from the Third Circuit.

Regulation

Environmental Regulation

Epsilon is subject to various federal, state and local laws and regulations governing the handling, management, disposal and discharge of materials into the environment or otherwise relating to the protection of human health, safety and the environment. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentrations of various substances, including water and waste, that can be released into the environment;
- limit or prohibit activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

Compliance with environmental laws and regulations increases Epsilon's overall cost of business, but has not had, to date, a material adverse effect on Epsilon's operations, financial condition or results of operations. In addition, it is not anticipated, based on current laws and regulations, that Epsilon will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, given that such laws and regulations are subject to change, Epsilon is unable to predict the ultimate cost of compliance or the ultimate effect on Epsilon's operations, financial condition and results of operations.

Climate Change

There is consensus in the international scientific community that increasing concentrations of greenhouse gas emissions ("GHG") in the atmosphere will produce changes to global, as well as local, climate. Scientists project that increased concentrations of GHGs will cause more frequent, and more powerful storms, droughts, floods and other climatic events. If such effects were to occur, our development and production operations, as well as operations of our third party providers and customers, could be adversely affected. To date, we have not developed a comprehensive plan to address potential impacts of climate change on our operations and there can be no assurance that any such impacts would not have an adverse effect on our financial condition and results of operations.

Attempts to address GHGs, as well as climate change more generally, have taken the form of local, state, national and international proposals. Broadly speaking, examples include cap-and-trade programs, carbon tax proposals, GHG reporting and tracking programs, and regulations that directly limit GHGs from certain sources.

In the United States, federal proposals are rooted in the EPA's "endangerment finding," that was upheld by the Supreme Court. Simply, EPA has concluded that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment. For example, the EPA adopted regulations that require Prevention of Significant Deterioration ("PSD") construction under Title V operating permit reviews for GHG emissions from certain large stationary sources that constitute major sources of emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards.

Rules requiring the monitoring and reporting of GHG emissions from designated sources in the United States on an annual basis, including, oil and natural gas production facilities and processing, transmission, storage and distribution facilities, which include certain of our operations, have been adopted. The EPA has expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities.

Federal agencies also have begun directly regulating emissions of methane from natural gas operations. In 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain facilities to reduce methane gas and volatile organic compound emissions. EPA published amendments to those regulations effective September 15, 2020. However, on January 20, 2021, President Biden issued an Executive Order directing EPA to consider suspending, revising or rescinding the September 15, 2020 amendments and also to consider proposing new regulations governing methane and volatile organic compound emissions from existing oil and gas sector operations.

In November 2016, the Bureau of Land Management ("BLM") published a final rule to reduce methane emissions by regulating venting, flaring, and leaking from oil and natural gas operations on public lands. A federal district court vacated much of that rule in October 2020 and that decision is now subject to an appeal.

Internationally, in April 2016, the United States joined other countries in entering into a non-binding agreement in France for nations to limit their GHG emissions through country-determined reduction goals every five years beginning in 2020 (the "Paris Agreement"). Although the Trump Administration subsequently announced plans to withdraw from the Paris Agreement, on January 20, 2021 President Biden issued an Executive Order providing that he was accepting the Paris Agreement on behalf of the United States.

In addition, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations on certain sources of funding for the energy sector. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities.

Epsilon is unable to predict the timing, scope and effect of any currently proposed or future, laws, regulations or treaties regarding climate change and GHG emissions. Any limits on GHG emissions, however, could adversely affect demand for the oil and natural gas that production operators produce, some of whom are our customers, which could thereby reduce demand for our gas gathering services. We are currently unable to calculate or predict the direct and indirect costs of GHG or climate change related laws, regulations and treaties, and accordingly, we cannot assure you that any such efforts will not have a material impact on our operations, financial condition and results.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices and has finalized a study of the potential environmental impacts of hydraulic fracturing activities. In 2014, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act of 1976 requesting comments related to disclosure for hydraulic fracturing chemicals. The Department of the Interior had released final regulations governing hydraulic fracturing on federal and Native American oil and natural gas leases which require lessees to file for approval of well stimulation work before commencement of operations and require well operators to disclose the trade names and purposes of additives used in the fracturing fluids. However, in December 2017, the Bureau of Land Management published a final rule rescinding the March 26, 2015 rule ("BLM 2015 Rule"), entitled "Natural gas and oil; Hydraulic Fracturing on Federal and Indian Lands." The primary purposes of the BLM 2015 Rule were to ensure that wells were constructed so as to protect water supplies, to ensure environmentally responsible management of fluids displaced by fracturing, and to provide public disclosure of chemicals used in fracturing operations. The net effect of the December 2017 rule making is to return the affected sections of the Code of Federal Regulations to the language that existed before the BLM's 2015 Rule. In addition, legislation has from time to time been introduced, but not adopted, in Congress to provide for additional federal regulation of hydraulic fracturing and to require additional disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances.

Epsilon is unable to predict the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing in the United States, but there can be no assurance that the direct and indirect costs of such laws and regulations (if enacted) would not materially and adversely affect Epsilon's operations, financial condition and results of operations.

Gathering System Regulation

Regulation of gathering facilities may affect certain aspects of Epsilon's business and the market for Epsilon's services. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the Federal Energy Regulatory Commission, or the FERC. The FERC regulates interstate natural gas transportation rates, terms and conditions of service, which affects the marketing of natural gas produced by Epsilon, as well as the revenues received for sales of Epsilon's natural gas.

The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or the NGA, and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation, gathering, and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the U.S. Congress and by FERC regulations.

Market for Our Common Equity and Related Stockholder Matters

Market Information. Commencing on February 19, 2019, the common shares of the Company trade on the NASDAQ Global Market with the ticker symbol ''EPSN.'' The last reported sales price of our common shares on the NASDAQ Global Market on March 22, 2023 was $5.11 per share.

Shareholders. We had approximately 675 shareholders of record as of February 21, 2023.

Dividends. On February 24, 2022, the Board of Directors approved a quarterly cash dividend of $0.0625 per common share. With the initiation of a cash dividend, Epsilon intends to pay regular quarterly dividends, with future dividend payments subject to quarterly review and approval by its Board of Directors. Epsilon made aggregate quarterly distributions of $5.9 million ($0.25 per share) during the year ended December 31, 2022.

Securities Authorized for Issuance under Equity Incentive Plans.

The following table sets out the number of common shares available to be issued upon exercise of outstanding options issued and the changes to the options outstanding for the year pursuant to our equity compensation plans and the weighted average exercise price of outstanding options for the periods indicated:

	As of December 31, 2022		As of December 31, 2021	
	Number of Options Outstanding	Weighted Average Exercise Price	Number of Options Outstanding	Weighted Average Exercise Price
Balance at beginning of period	218,750	$ 5.28	245,000	$ 5.27
Exercised	(138,750)	5.38	(16,250)	5.25
Expired/Forfeited	(10,000)	5.51	(10,000)	5.50
Balance at period-end	70,000	$ 5.03	218,750	$ 5.28
Exercisable at period-end	70,000	$ 5.03	218,750	$ 5.28

For the years ended December 31, 2022 and 2021, we had no warrants or other common share-related rights outstanding.

At December 31, 2022, under the 2020 Equity Incentive Plan (the "2020 Plan") (See Note 6, "Shareholders' Equity" of the Notes to the Consolidated Financial Statements), we are authorized to issue 2,000,000 common shares to employees and directors of the Company. As of that date, we had 449,131 common shares granted under the 2020 Plan. No more shares are authorized to be issued under our predecessor plan.

The following table sets out the number of time restricted common shares available to be issued upon vesting over the next three years and the changes during the year pursuant to our share compensation plans and the weighted average market price at date of issue for outstanding shares for the periods indicated:

	As of December 31, 2022		As of December 31, 2021	
	Number of Shares Outstanding	Weighted Average Grant Date Market Price	Number of Shares Outstanding	Weighted Average Grant Date Market Price
Balance non-vested Restricted Stock at beginning of period	166,002	$ 3.96	290,070	$ 3.41
Granted	289,231	6.28	48,000	5.04
Vested	(157,023)	4.34	(137,668)	3.98
Forfeited	—	—	(34,400)	3.68
Balance non-vested Restricted Stock at end of period	298,210	$ 6.00	166,002	$ 3.96

The following table sets out the number of performance-based common shares available to be issued upon vesting over the next three years and the changes during the year pursuant to our share compensation plans and the weighted average market price at date of issue for outstanding shares for the periods indicated:

	As of December 31, 2022		As of December 31, 2021	
	Number of Shares Outstanding	Weighted Average Grant Date Market Price	Number of Shares Outstanding	Weighted Average Grant Date Market Price
Balance non-vested Performance Shares at beginning of period	151,500	$ 3.84	193,167	$ 3.45
Granted	—	—	20,834	5.04
Vested	(135,667)	3.48	(62,501)	4.13
Balance non-vested Performance Shares at end of period	15,833	$ 3.71	151,500	$ 3.84

Recent Developments

None.

ITEM 1A. RISK FACTORS.

You should carefully consider the risks and uncertainties described below, together with all of the other information and risks included in, or incorporated by reference into this report, including our consolidated financial statements and the related notes thereto, before making any financial decisions relating to Epsilon.

Risks Related to Oil and Natural Gas Reserves

Our business is dependent on oil and natural gas prices, and any fluctuations or decreases in such prices could adversely affect our results of operations and financial condition.

Revenues, profitability, liquidity, ability to access capital and future growth prospects are highly dependent on the prices received for oil and natural gas. The prices of these commodities are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, and this volatility may continue in the future. The volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements. Also, prices for crude oil and prices for natural gas do not necessarily move in tandem. Declines in oil or natural gas prices would not only reduce revenue, but could also reduce the amount of oil and natural gas that can be economically produced and therefore potentially lower natural gas and oil reserve quantities. If the oil and natural gas industry continues to experience low prices, we may, among other things, be unable to meet all of our financial obligations or make planned expenditures.

Substantial and extended declines in oil and natural gas prices may result in impairments of proved natural gas and oil properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, spending will be required to be reduced, assets could be sold or funds may be borrowed to fund any such shortfall.

Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves, the failure of which could result in under-use of capital and in losses.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves that we may have at any particular time and the production from those reserves will decline over time as those reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. We cannot assure you that we will be able to locate and continue to locate satisfactory properties for acquisition or participation. Moreover, if we do identify such acquisitions or participations, we may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. We cannot assure you that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations, and the loss of the ability to use hydraulic fracturing (see risk factor regarding government legislation). Losses resulting from the occurrence of any of these risks could have a material adverse effect on our future results of operations, liquidity and financial condition.

Our reserve estimates may be inaccurate, and future net cash flows as well as our ability to replace any reserves are uncertain.

There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived thereof, including many factors beyond our control. The reserve and associated cash flow information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows thereof are based upon a number of variable factors and assumptions such as historical oil and natural gas prices, production levels, capital expenditures, operating and development costs, the effects of regulation, the accuracy and reliability of the underlying engineering and geologic data, and the availability of funds; all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected thereof and prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material.

In accordance with applicable securities laws, the technical report on our oil and natural gas reserves prepared by DeGolyer and MacNaughton, independent petroleum consultants, as of December 31, 2022 and 2021, or the DeGolyer Reserve Report, used SEC guideline prices and cost estimates in calculating net cash flows from oil and natural gas reserve quantities included within the report. Actual future net revenue will be affected by other factors such as actual commodity prices, production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived thereof will vary from the estimates contained in the DeGolyer Reserve Report, and such variations could be material. The DeGolyer Reserve Report is based in part on the assumed success of activities that we intend to undertake in future years. The oil and natural gas reserves and estimated cash flows to be derived therefrom contained in the DeGolyer Reserve Report will be reduced to the extent that such activities do not achieve the level of success assumed in the DeGolyer Reserve Report.

Our future oil and natural gas reserves, production, and derived cash flows are highly dependent on our successfully acquiring or discovering and developing new reserves. Without the continual addition of new reserves, any of our existing reserves and their production will decline as such reserves are exploited. A future increase in our reserves will depend not only on our ability to develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. There can be no assurance that our future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Risks Related to Stage of Development, Structure and Capital Resources

If there is a sustained economic downturn or recession in the United States or globally, natural gas and oil prices may fall and may become and remain depressed for a long period of time, which may adversely affect our results of operations. We may be unable to obtain additional capital required to implement our business plan, which could restrict our ability to grow.

Operations could also be adversely affected by general economic downturns or limitations on spending. An economic downturn and uncertainty may have a negative impact on our business. During 2022 and 2021, there was tremendous volatility in prices and available financing for oil and gas projects. There can be no assurance that we will be able to access capital markets to provide funding for future operations that would require additional capital beyond our current existing available capital on terms acceptable to us.

Substantial capital, which may not be available to us in the future, is required to replace and grow reserves.

We anticipate making capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If our revenues or reserves decline, we may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements, or for other corporate purposes. If debt or equity financing is available, there is no assurance that it will be on terms acceptable to us. Moreover, future activities may require us to alter our capitalization significantly. Additional capital raised through the issuance of common shares or other securities convertible into common shares may result in a change of control of us and dilution to shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our financial condition and results of operations.

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities, or reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt, equity financing or the proceeds from the sale of a portion or all of our interest in one or more projects will be available to meet these requirements or available on terms acceptable to us.

The borrowing base under our credit facility may be reduced in light of commodity price declines, which could limit us in the future.

Lower commodity volumes and prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to twice yearly redeterminations, as well as special redeterminations described in the credit agreement. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our credit agreement. In addition, we may be unable to access the equity or debt capital markets to meet our obligations, including any such debt repayment obligations.

The terms of our revolving credit facility may restrict our operations, particularly our ability to respond to changes or to take certain actions.

The contract that governs our revolving credit facility contains covenants that impose operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including restrictions on our ability, subject to satisfaction of certain conditions, to incur additional indebtedness, sell assets, enter into transactions with affiliates, and enter into or refrain from entering into hedging contracts.

In addition, the restrictive covenants in our revolving credit facility require us to maintain specified financial ratios and satisfy other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we may be unable to meet them.

A breach of the covenants or restrictions under the contract that governs our revolving credit facility could result in an event of default under the applicable indebtedness. Such a default may allow the creditors to accelerate the related debt. In the event our lenders accelerate the repayment of our borrowings, we may not have sufficient assets to repay that indebtedness.

Depending on forces outside our control, we may need to allocate our available capital in ways that we did not anticipate.

Because of the volatile nature of the oil and natural gas industry, we regularly review our budgets in light of past results and future opportunities that may become available to us. In addition, our ability to carry out operations may depend upon the decisions of other working interest owners in our properties. Accordingly, while we anticipate that we will have the ability to spend the funds available to us, there may be circumstances where, for sound business reasons, a reallocation of funds may be prudent.

We may issue debt to acquire assets or for working capital.

From time to time, we may enter into transactions to acquire assets or shares of other companies. These transactions may be financed partially or wholly with debt, which may increase our debt levels. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. Neither our articles of incorporation nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Our potential lenders will likely require security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default, such as bankruptcy, these lenders may foreclose on or sell our properties. The proceeds of any such sale would be applied to satisfy amounts owed to our lenders and other creditors, and only the remainder, if any, would be available to us.

Future equity transactions could result in dilution to existing stockholders.

We may make future acquisitions or enter into financing or other transactions involving the issuance of securities or the sale of a portion or all of an interest in one or more of our projects, all of which may be dilutive to existing security holders.

Competition in the natural gas and oil industry is intense, which may hinder our ability to contract for drilling equipment, and we may not be able to control the scheduling and activities of contracted drilling equipment.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. Past industry conditions have led to periods of extreme shortages of drilling equipment in certain areas of the United States. On the oil and natural gas properties that we do not operate, we will be dependent on such operators for the timing of activities related to such properties and may be largely unable to direct or control the activities of the operators.

Results of our drilling are uncertain, and we may not be able to generate high returns.

Our operations involve utilizing the latest drilling and completion techniques in order to maximize cumulative recoveries and generate high returns. If drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, or if crude oil and natural gas prices decline, the return on our investment in these areas may not be as attractive as anticipated. Further, less than anticipated results in developments could incur material write-downs of our oil and natural gas properties and the value of undeveloped acreage could decline in the future.

Extensive government legislation and regulatory initiatives could increase costs and impose burdensome operating restrictions that may cause operational delays.

Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into deep rock formations to stimulate crude oil or natural gas production, is often used in the completion of unconventional crude oil and natural gas wells. Currently, hydraulic fracturing is primarily regulated in the United States at the state level, which generally focuses on regulation of well design, pressure testing, and other operating practices.

However, some states and local jurisdictions across the United States, such as the State of New York, have begun adopting more restrictive regulation. Some members of the U.S. Congress and the EPA are studying environmental contamination related to hydraulic fracturing and the impact of fracturing on public health. In March 2015, the U.S. Congress introduced legislation to regulate hydraulic fracturing and require disclosure of the chemicals used in the hydraulic fracturing process, and may implement more stringent regulations in the future. Additionally, some states, such as the State of New York, have adopted, and others are considering, regulations that could restrict hydraulic fracturing. The ultimate status of such regulation is currently unknown. Any federal or state legislative or regulatory changes with respect to hydraulic fracturing could cause us to incur substantial compliance costs or result in operational delays, and the consequences of any failure to comply by us or our third-party operating partners could have a material adverse effect on our financial condition and results of operations.

Our corporate structure could result in incremental tax burden in certain circumstances.

Epsilon Energy Ltd. is an Alberta company. Epsilon Energy USA Inc. (Ohio corporation) may be a U.S. real property holding corporation (a "USRPHC") for U.S. federal income tax purposes if it is determined, at any time, that the fair market value of its assets that consist of "United States real property interests," as defined in the Internal Revenue Code, and applicable Treasury regulations, constitute at least 50% of the combined fair market value of our real estate interests and other business assets. If Epsilon Energy USA Inc. were a USRPHC, then Epsilon Energy Ltd.'s investment in Epsilon Energy USA Inc. would be a United States Real Property Interest (USRPI) for US federal tax purposes. As a result, the Foreign Investment in Real Property Tax Act, or "FIRPTA," would require Epsilon Energy Ltd. to pay U.S. federal income tax at the corporate income tax rates on capital gain distributions made by Epsilon Energy USA Inc. to Epsilon Energy Ltd. Distributions made out of earnings and profits are not expected to be subject to the FIRPTA tax but would be subject to U.S. withholding tax.

Our operations are currently geographically concentrated and therefore subject to regional economic, regulatory and capacity risks.

Approximately 91% and 93% of our production during fiscal 2022 and 2021, respectively was derived from our properties in the Marcellus Shale region of Pennsylvania. As a result of this geographic concentration, we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas. Additionally, we may be exposed to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in many or all of our wells within the Marcellus Shale.

Delays in business operations may reduce cash flows and subject us to credit risks.

In addition to the usual delays in payments by purchasers of oil and natural gas to us or to the operators, and the delays by operators in remitting payment to us, payments from these parties may be delayed by restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. In addition, the transition of one operator to another as the result of an operator being bought or sold could cause additional operational delays beyond our control. Any of these delays could reduce the amount of cash flow available for our business in a given period and expose us to additional third-party credit risks.

We depend on the successful acquisition, exploration and development of oil and natural gas properties to develop any future reserves and grow production and revenue in the future, and assessments of our assets may be subject to uncertainty.

Acquisitions of oil and natural gas companies and oil and natural gas assets are typically based on engineering and economic assessments made by independent engineers and our own assessments. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. In particular, the prices of, and markets for, oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on analysis by our internal engineers or reports by a firm of independent engineers that are not the same as the firm that we use for our year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm that we use.

We depend on third-party operators and our key personnel, and competition for experienced, technical personnel may negatively affect our operations.

Approximately 99% of our oil and natural gas properties are operated by third-party operators. As such, we will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. The objectives and strategy of those operators may not always be consistent with ours, and we have a limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues from our assets or could increase costs or create liability for the operator's failure to properly maintain the well and facilities and to adhere to applicable safety and environmental standards.

In addition to the operator, our success will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on us. We do not have key-person insurance in effect for management. The contributions of these individuals to our immediate operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense, and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Certain of our directors and officers are also directors of other companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the Conflicts Committee of our board of directors.

Our leasehold interests are subject to termination or expiration under certain conditions.

Our properties are held in the form of leases and working interests in leases, collectively referred to as "***leasehold interests***." If we or our joint venture partner fails to meet the specific requirement(s) of a particular leasehold interest, the leasehold interest may terminate or expire. There can be no assurance that any of the obligations required to maintain each leasehold interest will be met. The termination or expiration of a particular leasehold interest may have a material adverse effect on our financial condition and results of operations.

We may incur losses as a result of title deficiencies.

Although title reviews will be done according to industry standards before the purchase of most oil and natural gas-producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction in our ownership interest or of the revenue that we receive.

We may be exposed to third-party credit risk, and defaults by third parties could adversely affect us.

We are or may be exposed to third-party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production, derivative counterparties and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations.

We may not be insured against all of the operating risks to which we are exposed.

Our involvement in the exploration for and development of oil and natural gas properties may result in our becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although before drilling we plan to obtain insurance in accordance with industry standards to address certain of these risks, such insurance may not be available, be price-prohibitive, or contain limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable, or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks because of the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position and our results of operations.

Risks Related to Commodity Prices, Hedging and Marketing

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our oil and natural gas properties are substantially dependent on prevailing prices of oil and natural gas. Our ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States, the Middle East and elsewhere in the world; the actions of OPEC; governmental regulation; political stability in the Middle East and elsewhere; the foreign supply of oil and natural gas; the price of foreign imports; and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. There can be no assurance that recent commodity prices can be sustained over the life of our operations. There is substantial risk that commodity prices may decline in the future, although it is not possible to predict the time or extent of such decline.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings that may be available to us are in part determined by our borrowing base. A sustained material decline in prices from historical average prices could reduce our borrowing base, thereby reducing the bank credit available to us, which could require that a portion, or all, of our bank debt be repaid.

Hedging transactions may limit our potential gains or cause us to lose money.

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we will not benefit from such increases.

We are exposed to risks of loss in the event of nonperformance by our counterparties to our hedging arrangements. Some of our counterparties may be highly leveraged and subject to their own operating and regulatory risks. Despite our analysis, we may experience financial losses in our dealings with these and other parties with whom we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our counterparties could have a material adverse impact on our business, financial condition and results of operations.

Additionally, we may, due to circumstances beyond our control, be put in a position of over-hedging. If this occurs, our revenue could be adversely affected due to the necessity of buying gas at the current market rate in order to fulfill hedging sales obligations.

Market conditions or operation impediments may hinder our access to natural gas and oil markets or delay our production.

The marketability and price of oil and natural gas that we may produce, acquire or discover will be affected by numerous factors beyond our control. Our ability to market our natural gas may depend upon our ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets. This risk is somewhat mitigated by our 35% ownership of a gathering system in the Marcellus Shale in Pennsylvania. We may also be affected by extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, and many other aspects of the oil and natural gas business.

Investor sentiment towards climate change, fossil fuels, and sustainability could adversely affect our business and our share 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 energy companies, as well as to pressure lenders and other financial services companies to limit or curtail activities with energy companies. If these efforts are successful, our stock price and our ability to access capital markets may be negatively impacted.

Members of the investment community are also increasing their focus on sustainability practices, including practices related to GHGs and climate change, in the energy industry. As a result, we may face increasing pressure regarding our sustainability disclosures and practices. Additionally, members of the investment community may screen companies such as ours for sustainability performance before investing in our shares.

We are subject to complex laws and regulations, including environmental regulations that can have a material adverse effect on the cost, manner and feasibility of doing business.

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Our operations may require licenses and permits from various governmental authorities. There can be no assurance that we will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at our projects. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and natural gas companies of similar size.

Environmental and health and safety risks may adversely affect our business.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills and releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental regulations, we cannot assure you that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

We must also conduct our operations in accordance with various laws and regulations concerning occupational safety and health. Currently, we do not foresee expending material amounts to comply with these occupational safety and health laws and regulations. However, since such laws and regulations are frequently changed, we are unable to predict the future effect of these laws and regulations.

Risks Related to Internal Controls

For as long as we are an "emerging growth company," we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to some other public companies.

As an "emerging growth company" as defined in the JOBS Act, we are permitted to, and intend to, rely on exemptions from certain disclosure requirements. We are an emerging growth company until the earliest of:

- the last day of the fiscal year during which we have total annual gross revenues of $1.235 billion or more;
- the last day of the fiscal year following the fifth anniversary of the date of our first issuance of common equity securities under an effective Securities Act registration statement (December 31, 2019);
- the date on which we have, during the previous 3-year period, issued more than $1 billion in non-convertible debt; or
- the date on which we are deemed a "large accelerated filer" as defined under the federal securities laws.

For so long as we remain an "emerging growth company," we will not be required to:

- have an auditor report on our internal control over financial reporting pursuant to the Sarbanes-Oxley Act of 2002;
- comply with any requirement that may be adopted by the Public Company Accounting Oversight Board regarding mandatory audit firm rotation or a supplement to the auditor's report providing additional information about the audit and the financial statements (auditor discussion and analysis);
- submit certain executive compensation matters to shareholder approval (requiring a non-binding shareholder vote to approve golden parachute arrangements in connection with mergers and certain other business combinations, and advisory votes on executive compensation pursuant to the "say on frequency" and "say on pay" provisions under the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010; and
- include detailed compensation discussion and analysis in our filings under the Securities Exchange Act of 1934 (the "Exchange Act") and instead may provide a reduced level of disclosure concerning executive compensation.

In addition, the JOBS Act provides that an "emerging growth company" can take advantage of the extended transition period for complying with new or revised accounting standards. We have elected to take advantage of the extended transition period, which allows us to delay the adoption of new or revised accounting standards until those standards apply to private companies. As a result of this election, our financial statements may not be comparable to public companies that comply with new or revised accounting standards.

Because of these exemptions, some investors may find our common shares less attractive, which may result in a less active trading market for our common shares, and our shares price may be more volatile.

If we fail to establish and maintain proper disclosure or internal controls, our ability to produce accurate financial statements and supplemental information or comply with applicable regulations could be impaired.

As we grow, we may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to train and manage our employee base.

We must maintain effective disclosure controls and procedures. We must also maintain effective internal controls over financial reporting or, at the appropriate time, our independent auditors will be unwilling or unable to provide us with an unqualified report on the effectiveness of our internal controls over financial reporting as required by Section 404(b) of the Sarbanes-Oxley Act, once we become subject to those requirements. If we fail to maintain effective controls, investors may lose confidence in our operating results, the price of our common shares could decline and we may be subject to litigation or regulatory enforcement actions.

Risks Related to Gathering System

Because of the natural decline in production from existing wells, our success depends on the Anchor Shippers' economically developing the remaining Marcellus Shale reserves.

Our natural gas gathering system is dependent upon the level of production from natural gas wells, from which production will naturally decline over time. In order to maintain or increase throughput levels on our gathering system and compression facility, we must continually develop reserves within the Auburn GGS boundary or obtain new supplies external to the Auburn GGS boundary. Developing reserves within the system boundary is the priority as external natural gas volumes have a contractual gathering rate that is 25% of the Anchor Shipper rate. The primary factors affecting our ability to obtain new supplies of natural gas is the level of successful drilling activity from the Anchor Shippers, of which Epsilon is one, as well as our ability to compete for volumes from successful new wells drilled by third parties proximate to our system. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on our pipelines and the utilization rates of our compression facility would decline, which could have an adverse effect on our business, results of operations, financial position and cash flows. Although gross throughput at the Auburn CF has declined from 2018-2022, the share of Anchor Shipper gas has increased.

The gathering rate on the Auburn GGS is subject to a cost-of-service model which could result in a non-competitive gathering rate and reduced throughput.

The gathering rate charged by the Auburn GGS is determined by a cost-of-service model whereby the Anchor Shippers in the system, of which Epsilon is one, dedicate acreage and reserves to the gas gathering system in exchange for the Auburn GGS owners agreeing to a contractual rate of return on invested capital. The term of this arrangement is 15 years commencing in 2012 and expiring in 2026 with an 18% rate of return. Each year, the Auburn GGS historical and forecast throughput, revenue, operating expenses and capital expenditures are entered into the cost-of-service model. The model then computes the new gathering rate that will yield the contractual rate of return to the Auburn GGS owners. In January 2027, the Auburn GGS will transition to a fixed gathering rate.

Under the cost-of-service model, if total throughput on the system is lower than forecasted in the prior year, the gathering rate will increase. The 2022 model forecasts 276 Bcf throughput from 2022-2026 (approximately 69% of current capacity at the 550 psig design suction pressure) which resulted in a \$0.40 gathering rate. If the gathering rate on the Auburn GGS increases, it could result in reduced or deferred development in the Auburn GGS. In one unlikely scenario, if no further development activity beyond work in progress occurs in the Auburn GGS, forecast throughput from 2022-2026 is expected to decline to 205 Bcf (approximately 52% of current capacity at the 550 psig design suction pressure) resulting in a still acceptable \$0.62 gathering rate. Although the Anchor Shippers have dedicated their reserves to the Auburn GGS, they are under no obligation to develop the reserves.

Because of the large supply of gas, and limited availability of transportation out of the Marcellus Shale area, our gas is subject to a price differential.

Differential is an energy industry term that refers to the discount or premium received for the sale of a petroleum product at a specific location relative to a nationally recognized sales hub. In the Marcellus Shale, natural gas is significantly discounted to Henry Hub and the size of the differential can be volatile. Many factors influence the size and duration of differentials including local supply / demand imbalances, seasonal fluctuations in demand, transportation availability and cost, as well as the regulatory environment as it pertains to constructing new transportation pipelines. In Northeast Pennsylvania, negative differentials have persisted for many years due to rapid increases in supply as a result of advances in well completion techniques. Despite substantial increases in local demand for natural gas coupled with pipeline expansions, optimizations, and new pipelines that have been brought into service, the natural gas differential in Northeast Pennsylvania remains significant. There is no guarantee that future demand or pipeline transportation projects will eliminate this differential, and it will therefore remain a significant risk to demand for transportation service on the Auburn GGS, and therefore Epsilon's revenues and cash flows.

We compete with other operators in our gas gathering energy businesses.

Although the Anchor Shippers have dedicated their acreage and reserves to the Auburn GGS, the Auburn GGS may not be chosen by other producers in these areas to gather and compress the natural gas extracted. We compete with other companies, including co-owners of the Auburn GGS who operate other systems, for any such production from non-Anchor Shippers on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets. Competition in natural gas gathering is based in large part on existing assets, reputation, efficiency, system reliability, gathering system capacity and pricing arrangements. Our key competitors in the natural gas gathering business include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to non-Anchor Shippers we serve, and those producers may also elect to construct proprietary gas gathering systems. A significant increase in competition in the gas gathering industry could have a material adverse effect on our financial position, results of operations and cash flows.

Several of our assets have been in service for many years may require significant expenditures to maintain them. As a result, our maintenance or repair costs may increase in the future.

Our gathering lines and compression facility are generally long-lived assets, and many of such assets have been in service for many years. The age and condition of our assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our gathering rate and competitive position.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management will not be able to completely eliminate such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Generally, our customers are rated investment grade, are otherwise considered creditworthy, or may be required to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies cannot completely eliminate customer and counterparty credit risk. Our customers and counterparties include natural gas producers whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities. In a low commodity price environment certain of our customers could be negatively impacted, causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts. To the extent one or more of our key customers commences bankruptcy proceedings, our contracts with the customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness, and any resulting increase in nonpayment and/or nonperformance by them could cause us to write down or write off accounts receivable. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows, and financial condition.

Prices for natural gas in Northeast Pennsylvania are volatile and are subject to significant discounts from pricing at Henry Hub. This discount and volatility has and could continue to adversely affect our financial results, cash flows, access to capital and ability to maintain our existing businesses.

Our revenues, operating results, and future rate of growth depend primarily upon the price of natural gas in Northeast Pennsylvania which is currently volatile and significantly discounted to natural gas at Henry Hub due to insufficient interstate pipeline capacity out of the region. This volatility and discount has adversely impacted reserve development in the past, and could do so again in the future. A slowing pace relative to the cost of service model forecast or complete halt to the development of Anchor Shipper reserves will impact our financial results, cash flows, and access to capital.

The financial condition of our natural gas gathering businesses is dependent on the continued availability of natural gas supplies and demand for those supplies in the markets we serve.

Our ability to expand our natural gas gathering business primarily depends on the level of drilling and production by the Anchor Shippers. Production from existing wells with access to our gathering systems will naturally decline over time. The amount of natural gas reserves underlying these existing wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. We do not obtain independent evaluations of the third-party natural gas reserves flowing into our systems and compression facilities. Demand for our services is dependent on the demand for gas in the markets we serve. Alternative fuel sources such as electricity, coal, fuel oils, or nuclear energy could reduce demand for natural gas in our markets and have an adverse effect on our business. A failure to obtain access to sufficient natural gas supplies or a reduction in demand for our services in the markets we serve could result in impairments of our assets and have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions.

There are operational risks associated with gathering and compression of natural gas, including:

- Hurricanes, tornadoes, floods, extreme weather conditions and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas, brine, or industrial chemicals;
- Operator error;
- Damage caused by third-party activity, such as operation of construction equipment;
- Pollution and other environmental risks;
- Fires, explosions, craterings, and blowouts; and
- Terrorist attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial financial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

The information required by Item 2 is contained in "*Item 1. Business.*"

ITEM 3. LEGAL PROCEEDINGS.

On March 10, 2021, Epsilon filed a complaint against Chesapeake Appalachia, LLC ("Chesapeake") in the United States District Court for the Middle District of Pennsylvania, Scranton, Pennsylvania ("Middle District"). Epsilon claims that Chesapeake has breached a settlement agreement and several operating agreements ("JOAs") to which Epsilon and Chesapeake are parties. Epsilon asserts that Chesapeake has failed to cooperate with Epsilon's efforts to develop resources in the Auburn Development, located in Northeast Pennsylvania, as required under both the settlement agreement and JOAs.

Epsilon requested a preliminary injunction but was unsuccessful in obtaining that injunction. Epsilon filed a motion to amend its original Complaint. Chesapeake opposed. The Court ruled in Epsilon's favor and allowed Epsilon's amendment. Chesapeake moved to dismiss the amended Complaint. The Court granted the motion to dismiss on a narrow issue without prejudice to Epsilon's right to file a new lawsuit based on new proposals made after the Court's decision. Epsilon filed a motion for reconsideration of that decision, but the court denied the motion for reconsideration on January 18, 2022.

Epsilon filed a notice of appeal on February 15, 2022 challenging both the motion to dismiss and motion for reconsideration decisions. Chesapeake filed a cross-appeal on March 1, 2022. A briefing schedule was set and briefing closed October 14, 2022. Oral argument was held in January 2023. A decision on the appeal is not expected until mid-2023.

Epsilon re-filed a complaint against Chesapeake in the Middle District on May 9, 2022. Epsilon generally asserts similar claims as in the previous suit, pursuing declaratory judgment claims regarding Chesapeake's obligation to Epsilon to cooperate with Epsilon's efforts in the Auburn Development and regarding Chesapeake's obstruction of Epsilon's efforts with the Pennsylvania Department of Environmental Protection permitting process but not based on specific well proposals. Chesapeake filed a motion to stay pending a decision on the Third Circuit appeal, which was granted. The matter is stayed pending a decision from the Third Circuit.

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.

The information required by Item 201 of Regulation S-K is contained in ''*Item 1. Business*.''

On April 6, 2022 and December 31, 2022, our Board made grants to our directors and employees, entitling them to receive an aggregate of 89,925 common shares and 43,096 common shares, respectively, which shall not be issued to the award recipients unless certain time or performance based vesting criteria, as applicable, are met, in which case the vesting will occur in three equal parts on the succeeding periods ending on December 31.

On July 1, 2022, our Board made grants to a director of 18,000 common shares, and to our new CEO and CFO, entitling them to receive an aggregate of 138,210 common shares which shall not be issued to the award recipients unless certain time or performance based vesting criteria, as applicable, are met, in which case the vesting will occur in equal parts over a three-year and four-year period, respectively. The awards were made under the 2020 Equity Incentive plan in accordance with Rule 701 promulgated under the Securities Act.

Commencing on March 8, 2022, the Company entered into a share repurchase program conducted in accordance with Rule 10b-18 promulgated under the Exchange Act. The Company was authorized to repurchase up to 1,183,410 of its outstanding common shares, representing 5% of the outstanding common shares of the Company as of February 24, 2022. The program ended on March 7, 2023.

The Company funded the purchases out of available cash and did not incur debt to fund the share repurchase program. The shares are accounted for as treasury shares until such a time as they are retired.

ITEM 6. [RESERVED.]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion is intended to assist in the understanding of trends and significant changes in or results of operations and the financial condition of Epsilon Energy Ltd. and its subsidiaries for the periods presented. This section should be read in conjunction with the audited consolidated financial statements as of December 31, 2022 and 2021 and for the years then ended together with accompanying notes.

Overview

Epsilon Energy Ltd. (the "Company") is a North American onshore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves. Our primary area of operation is Pennsylvania.

At December 31, 2022 our total estimated net proved reserves were 90,040 MMcf of natural gas reserves, 491,226 Bbls of NGL reserves, and 211,059 Bbls of oil and other liquids, and we held leasehold rights to approximately 75,954 gross (13,625 net) acres. We have natural gas production in Pennsylvania, and natural gas, oil and other liquid production from our operated and non-operated wells in Oklahoma.

We are committed to disciplined capital allocation which could include shareholder returns in the form of dividends and/or share buybacks. We seek to maintain a strong balance sheet and liquidity to allow us to opportunistically invest in both our existing project areas and potential new projects.

To date, our investments have been focused on the Marcellus Shale unconventional reservoir in Pennsylvania ("PA"). Our PA assets are supported by our 35% ownership in the Auburn GGS. Over the last two years, we have also been active in our position in the NW Stack area of Oklahoma ("OK"). We have a substantial remaining drillable location inventory within our existing leasehold in PA and OK.

The Company also seeks to identify new opportunities in onshore North American natural gas and oil basins. In the second half of 2022, we evaluated several potential investments outside our existing projects, with a focus on the Northeastern United States. We expect to expand our area of interest in 2023 to selectively consider potential investments in other North American gas and oil basins.

During 2022, we realized net income of $35.4 million as compared to net income of $11.6 million for 2021.

At December 31, 2022, our total estimated net proved developed reserves were 80,795 MMcfe, an increase of 10% from December 31, 2021. The increase is mainly attributable to revisions to previous estimates and transfers from proved undeveloped.

At December 31, 2022, our total estimated net proved reserves were 94,254 MMcfe, a 20% decrease from December 31, 2021. The decrease in our total proved reserves is due to a change in our previously adopted development plan, primarily attributable to estimated proved undeveloped reserves in PA and OK that shifted into the probable reserve category under SEC guidelines due to timing. As a non-operating working interest owner, we often do not have direct control or visibility over the pace of investment in our assets by the operator. We anticipate reevaluating these reserves once we have line of sight on development timing.

Our standardized measure of discounted future net cash flows as of December 31, 2022 and 2021 was $145.8 million and $77.7 million, respectively. This measure of discounted future net cash flows does not include any estimate for future cash flows generated by our gathering system assets.

Results of Operations

The following review of operations for the periods presented below should be read in conjunction with our consolidated financial statements and the notes thereto.

Revenues

During the year ended December 31, 2022, revenues increased $27.6 million, or 65%, to $70.0 million from $42.4 million during the year ended December 31, 2021 due primarily to increased prices.

Revenue and volume statistics for the years ended December 31, 2022 and 2021 were as follows:

	Year ended December 31, 2022	Year ended December 31, 2021
Revenues		
Pennsylvania		
Natural gas revenue	**$ 53,759,354**	**$ 29,909,651**
Volume (MMcf)	9,026	9,830
Avg. Price ($/Mcf)	$ 5.96	$ 3.04
Gathering system revenue	**$ 8,085,512**	**$ 7,865,825**
Total PA Revenues	**$ 61,844,866**	**$ 37,775,476**
Oklahoma		
Natural gas revenue	**$ 3,189,380**	**$ 1,798,534**
Volume (MMcf)	477	403
Avg. Price ($/Mcf)	$ 6.68	$ 4.46
Natural liquids revenue	**$ 1,733,129**	**$ 1,053,486**
Volume (MBO)	44.1	29.3
Avg. Price ($/Bbl)	$ 39.31	$ 35.98
Oil and condensate revenue	**$ 3,195,334**	**$ 1,776,496**
Volume (MBO)	32.2	25.1
Avg. Price ($/Bbl)	$ 99.24	$ 70.70
Total OK Revenues	**$ 8,117,843**	**$ 4,628,516**
Total Revenues	**$ 69,962,709**	**$ 42,403,992**

Upstream natural gas revenue for the year ended December 31, 2022 increased by $25.2 million, or 80%, over 2021. An increase of $27.5 million was due to higher natural gas prices partially offset by a reduction of $2.3 million due to lower volumes being produced due to natural decline of the wells.

Upstream natural gas liquids revenue for the year ended December 31, 2022 increased by $0.7 million, or 65% over 2021. This was a result of increased production from new wells in addition to higher NGL prices.

Upstream oil and other liquids revenue for the year ended December 31, 2022 increased by $1.4 million, or 80% over 2021. This was a result of increased production from new wells in addition to higher oil prices.

Gathering system revenue for the year ended December 31, 2022 increased by $0.2 million, or 3% over 2021. This was the result of increased throughput in the system. Revenues derived from transporting and compressing our production, which have been eliminated from gathering system revenues amounted to $1.5 million and $1.6 million, respectively, for the years ended December 31, 2022 and 2021.,

Operating Costs

The following table presents total cost and cost per unit of production (Mcfe), including ad valorem, severance, and production taxes for the years ended December 31, 2022 and 2021:

	Year ended December 31, 2022	Year ended December 31, 2021
Lease operating costs	$ 7,128,631	$ 6,303,055
Gathering system operating costs	2,287,763	2,321,329
	$ 9,416,394	**$ 8,624,384**
Upstream operating costs—Total $/Mcfe	0.72	0.60
Gathering system operating costs $/Mcf	0.15	0.30

Operating costs include the effects of elimination entries to remove the gathering fees paid to Epsilon's ownership in the gathering system. Prior to the year ended December 31, 2022, the gathering fees were netted from the gathering system operating costs. For the year ended December 31, 2022, the Company determined that it would be more appropriate to net the $1.5 million fees from the upstream lease operating costs. To be consistent with the current presentation, the prior year elimination of $1.6 million has been reclassed as well.

Upstream operating costs consist of lease operating expenses necessary to extract natural gas and oil, including gathering and treating the natural gas and oil to ready it for sale. For the year ended December 31, 2022, upstream operating costs increased by $0.8 million, or 13.1% from the same period in 2021. The increase was due to extraordinary plugging and abandonment costs related to atypical wellbore conditions in two older vintage wells in Pennsylvania, which is not representative of the other wells.

Gathering system operating costs consist primarily of rental payments for the natural gas fueled compression units and overhead fees due to the system's operator. For the year ended December 31, 2022, gathering system operating costs decreased by $0.03 million, or 1.4% from the same period in 2021.

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

	Year ended December 31,	
	2022	2021
Depletion, depreciation, amortization and accretion	**$ 6,438,511**	**$ 6,627,016**

Natural gas and oil and gathering system assets are depleted and depreciated using the units of production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved and unproved properties, the reserve base used to calculate depreciation and depletion is total proved reserves. At this time, the Company has only minimal leasehold acquisition costs. For natural gas and oil development and gathering system costs, the reserve base used to calculate depletion and depreciation is proved developed reserves. A reserve report is prepared as of December 31, each year.

Depreciation expense includes amounts pertaining to our office furniture and fixtures, leasehold improvements, computer hardware. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, ranging from 3 to 7 years. Also included in depreciation expense is an amount pertaining to buildings owned by the Company. Depreciation for the buildings is calculated using the straight-line method over an estimated useful life of 30 years.

Accretion expense is related to the asset retirement costs.

During the year ended December 31, 2022, DD&A expense was generally consistent compared to the same period in 2021, decreasing by $0.2 million, or 3%.

Impairment

	Year ended December 31,	
	2022	2021
Impairment	**$ —**	**$ 153,058**

We perform a quantitative impairment test whenever events or changes in circumstances indicate that an asset group's carrying amount may not be recoverable, over proved properties using the published NYMEX forward prices, timing, methods and other assumptions consistent with historical periods. When indicators of impairment are present, GAAP requires that the Company first compare expected future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair values is required. Additionally, GAAP requires that if an exploratory well is determined not to have found proved reserves, the costs incurred, net of any salvage value, should be charged to expense.

For the year ended December 31, 2022, no impairment was recorded. For the year ended December 31, 2021, the Company recognized dry hole costs of $0.15 million.

Gain (Loss) on Sale of Properties

	Year ended December 31,	
	2022	2021
Gain on sale of assets	**$ 221,642**	**$ 484,902**

For the year ended December 31, 2022, the Company recorded a gain for a well-bore only asset sale and conveyance and partial release of oil and gas leases in Oklahoma. For the year ended December 31, 2021, the Company recorded a gain on the sale of the shallow rights leases and wells in Oklahoma.

General and Administrative ("G&A")

	Year ended December 31,	
	2022	2021
General and administrative	**$ 7,346,438**	**$ 6,831,816**

G&A expenses consist of general corporate expenses such as compensation, legal, accounting and professional fees, consulting services, travel and other related corporate costs such as stock options granted and restricted shares of stock granted and the related non-cash compensation.

G&A expenses increased by $0.5 million, or 8%, during the year ended December 31, 2022 from 2021. Increased compensation costs of $1.3 million associated with the management transition was offset by a decrease in legal fees by $0.8 million.

Interest Expense

	Year ended December 31,	
	2022	2021
Interest expense	**$ 50,782**	**$ 101,382**

Interest expense relates to the interest and commitment fees paid on the revolving line of credit.

Interest expense decreased by $0.05 million, or 50%, during the year ended December 31, 2022 from 2021. The decrease is due to the reduction in the borrowing base on our line of credit during this time.

Net gain (loss) on commodity contracts

	Year ended December 31,	
	2022	2021
Gain (loss) on derivative contracts	**$ 236,077**	**$ (4,482,909)**

During the years ended December 31, 2022 and 2021, we entered into NYMEX Henry Hub ("HH") Natural Gas Futures swaps, Dominion basis swaps, and two-way costless collar derivative contracts for the purpose of hedging our physical natural gas sales revenue. The amounts recorded represent the fair value changes on our derivative instruments during the year. For the year ended December 31, 2022, the Company paid net cash settlements of $1,225,837. For the year ended December 31, 2021, the Company paid net cash settlements of $4,243,085.

In April 2022, the Company added NYMEX HH collars totaling 1.2 Bcf and basis swaps totaling 1.2 Bcf. NYMEX HH prices generally increased throughout the first three quarters of 2022 resulting in realized losses for the year ended December 31, 2022.

In February 2021, the Company added Henry Hub collars totaling 3.96 Bcf and basis swaps totaling 0.31 Bcf. In August 2021, the Company added Henry Hub swaps totaling 0.46 Bcf and basis swaps totaling 1.10 Bcf. NYMEX HH prices generally increased throughout 2021 resulting in large realized losses for the year ended December 31, 2021.

At December 31, 2022, the Company had outstanding NYMEX HH swaps totaling 1.07 Bcf with a trade price of $5.212 and Tennessee Z4 basis swaps totaling 1.07 Bcf with a trade price of ($1.25) to hedge a portion of expected volumes for the contract period of April 2023 to October 2023.

Other Income (Expense)

	Year ended December 31,	
	2022	**2021**
Interest income and other income	**$ 353,408**	**$ 39,995**

During the year ended December 31, 2022, interest income increased by $0.4 million, or 877%, during the year ended December 31, 2022 from the same period in 2021. This increase was primarily due to the utilization of additional financial instruments with higher prevailing interest rates in 2022.

Net Income Compared to Adjusted EBITDA

	Year ended December 31,	
	2022	**2021**
Net income	$ 35,354,679	$ 11,627,517
Add Back:		
Net interest expense	(402,095)	62,517
Income tax expense	12,157,487	4,440,508
Depreciation, depletion, amortization, and accretion	6,438,511	6,627,016
Impairment expense	—	153,058
Stock based compensation expense	1,021,026	956,084
(Gain) loss on derivative contracts net of cash received or paid on settlement	(1,461,914)	239,824
Foreign currency translation loss	(845)	1,454
Adjusted EBITDA	$ 53,106,849	$ 24,107,978

We define Adjusted EBITDA as earnings before (1) net interest expense, (2) taxes, (3) depreciation, depletion, amortization and accretion expense, (4) impairments of natural gas and oil properties, (5) non-cash stock compensation expense, (6) gain or loss on derivative contracts net of cash received or paid on settlement, and (7) other income. Adjusted EBITDA is not a measure of financial performance as determined under U.S. GAAP and should not be considered in isolation from or as a substitute for net income or cash flow measures prepared in accordance with U.S. GAAP or as a measure of profitability or liquidity.

Additionally, Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We have included Adjusted EBITDA as a supplemental disclosure because its management believes that EBITDA provides useful information regarding our ability to service debt and to fund capital expenditures. It further provides investors a helpful measure for comparing operating performance on a "normalized" or recurring basis with the performance of other companies, without giving effect to certain non-cash expenses and other items. This provides management, investors and analysts with comparative information for evaluating us in relation to other natural gas and oil companies providing corresponding non-U.S. GAAP financial measures or that have different financing and capital structures or tax rates. These non-U.S. GAAP financial measures should be considered in addition to, but not as a substitute for, measures for financial performance prepared in accordance with U.S. GAAP. The table above sets forth a reconciliation of net income to Adjusted EBITDA, which is the most directly comparable measure of financial performance calculated under U.S. GAAP and should be reviewed carefully.

Capital Resources and Liquidity

Cash Flow

The primary source of cash during the years ended December 31, 2022 and 2021 was funds generated from operations. For the years ended December 31, 2022 and 2021, cash was primarily used for operations, as well as the development of natural gas and oil properties, the buyback of common shares through our share repurchase program, and the pre-payment of income taxes. In 2022, we began paying dividends quarterly, which totaled $5.9 million.

At December 31, 2022, we had a working capital surplus of $51.0 million, an increase of $26.9 million from the $24.1 million surplus at December 31, 2021. The surplus increased from December 31, 2021 primarily due to the increase in realized prices during 2022. We anticipate that our current cash balance, cash flows from operations, and available sources of liquidity to be sufficient to meet our cash requirements.

Year ended December 31, 2022 compared to 2021

During the year ended December 31, 2022, $38.0 million was provided by our operating activities, compared to $20.0 million in 2021, a $18.0 million, or 90%, increase. The increase was mainly due to the increase in realized prices resulting in increased revenue.

We used $7.9 million for investing activities during the year ended December 31, 2022, compared to $4.4 million in 2021, a $3.4 million, or 77%, increase. This was spent primarily on upstream development costs in Pennsylvania and Oklahoma.

During the year ended December 31, 2022, $12.0 million of cash used for financing activity was related to the repurchase of our common shares and the payment of quarterly dividends. This was offset by $0.7 million of proceeds from the exercise of stock options. During the year ended December 31, 2021, $2.3 million of cash was used for financing activity, which was primarily related to the repurchase of our common shares.

Credit Agreement

The Company has a senior secured credit facility which includes a total commitment of up to $100 million. The effective borrowing base is $30 million, which is subject to semi-annual redetermination. There are currently no borrowings under the facility. If we decide to access the facility, depending on the level of borrowing, we might need to increase our hedging activity. Borrowings from the Facility may be used for the acquisition and development of oil and gas properties, investments in cash flow generating assets complimentary to the production of oil and gas, and for letters of credit and other general corporate purposes. Upon each advance, interest is charged at the highest of a) the Prime Rate, or b) the sum of the Federal Funds Rate plus 0.5%, plus an applicable margin (0.25%-1.25%, based on percentage utilization on the facility).

The facility matures on March 1, 2024.

Effective April 6, 2021, the agreement was amended to extend the maturity date to March 1, 2024. In addition, the agreement was amended to include a *Benchmark Replacement* definition and transition plan to be used at such time when the LIBOR rate is discontinued.

On February 10, 2023, Epsilon Energy USA entered into the Ninth Amendment of the Credit Agreement. The borrowing base was increased to $30 million. LIBOR was removed as a reference option in the calculation of interest. Hedging requirements were amended to be between 0%-62.5% of the 24-month projected production volumes, based on percentage utilization on the facility. Also, cash distributions to the parent company (Epsilon Energy Ltd.) were allowed if the facility is < 80% utilized and the leverage ratio (total debt / income adjusted for interest, taxes and non-cash amounts) is less than 2.

The bank has a first priority security interest in the tangible and intangible assets of Epsilon Energy USA, Inc. to secure any outstanding amounts under the agreement. Under the terms of the agreement, the Company must maintain the following covenants:

- Interest coverage ratio greater than 3 (income adjusted for interest, taxes and non-cash amounts / cash interest expense)
- Current ratio greater than 1 (current assets / current liabilities)
- Leverage ratio less than 3.5 (total debt / income adjusted for interest, taxes and non-cash amounts)

We were in compliance with the financial covenants of the agreement as of December 31, 2022.

Repurchase Transactions

Commencing on March 8, 2022, we implemented a plan to repurchase our issued and outstanding common shares and to return capital to our shareholders. We used cash on hand to fund these repurchases. During the year ended December 31, 2022, we repurchased 982,500 common shares of the maximum of 1,183,410 authorized for repurchase and spent $6,234,879 under the plan. The repurchased stock had an average price of $6.32 per share (excluding commissions) and was subsequently retired during the year ended December 31, 2022.

In 2023, we repurchased 190,700 common shares at an average price of $5.82 per share (excluding commissions) before the plan terminated on March 7, 2023.

Commencing on January 1, 2021, we implemented a plan to repurchase our issued and outstanding common shares. The plan terminated on December 31, 2021. We used cash on hand to fund these repurchases. During the year ended December 31, 2021, we repurchased 534,015 common shares of the maximum of 1,193,000 authorized for repurchase and spent $2,423,007 under the plan. The repurchased stock had an average price of $4.51 per share (excluding commissions) and was subsequently retired during the year ended December 31, 2022.

On March 9, 2023, the Board of Directors authorized a new share repurchase program of up to 2,292,644 common shares, representing 10% of the outstanding common shares of Epsilon, for an aggregate purchase price of not more than US $15.0 million. The program is pursuant to a normal course issuer bid and will be conducted in accordance with Rule 10b-18 under the Exchange Act. The program will commence on March 27, 2023 and end on March 26, 2024, unless the maximum amount of common shares is purchased before then or Epsilon provides earlier notice of termination.

Derivative Transactions

The Company has entered into hedging arrangements to reduce the impact of natural gas price volatility on operations. By removing the price volatility from a significant portion of natural gas production, the potential effects of changing prices on operating cash flows have been mitigated, but not eliminated. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices.

At December 31, 2022, Epsilon's outstanding natural gas commodity swap contracts consisted of the following:

Derivative Type	Volume (MMbtu)	Weighted Average Price ($/MMbtu) Swaps	Basis Differential	Fair Value of Asset December 31, 2022
2023				
NYMEX Henry Hub swap	1,070,000	$ 5.21	$ —	$ 1,219,865
Tennessee Z4 basis swap	1,070,000	$ —	$ (1.25)	2,225
	2,140,000			$ 1,222,090

Contractual Obligations

We enter into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that we have committed to capital expenditures equal to approximately one quarter of our capital budget by means of giving the necessary authorizations to the asset operator to incur the expenditures in a future period. Current commitments amounted to approximately $0.8 million, all of which we expect to incur in 2023.

Based on current natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet liquidity needs for the next 12 months and beyond, including satisfying our financial obligations and funding our operating and development activities.

Off Balance Sheet Arrangements

As of December 31, 2022 and 2021, we had no off-balance sheet arrangements.

Summary of Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements and accompany notes, which have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP, and SEC rules which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their application. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Described below are the most significant accounting policies we apply in preparing our consolidated financial statements. We also describe the most significant estimates and assumptions we make in applying these policies.

Proved Natural Gas and Oil Reserves

Our engineers estimate proved natural gas and oil reserves in accordance with SEC regulations, which directly impact financial accounting estimates, including depreciation, depletion and amortization and impairments of proved properties and related assets. Proved reserves represent estimated quantities of crude oil and condensate, NGLs and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved natural gas and oil reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. There are uncertainties inherent in the interpretation of such data, as well as the projection of future rates of production and timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. Accordingly, there can be no assurance that ultimately, the reserves will be produced, nor can there be assurance that the proved undeveloped reserves will be developed within the period anticipated. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. We cannot predict the types of reserve revisions that will be required in future periods. For related discussion, see the sections titled "Risk Factors" and "Supplemental Information to Consolidated Financial Statements."

Unproved Natural Gas and Oil Properties

Unproved properties generally consist of costs incurred to acquire unproved leases. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as an impairment of natural gas and oil properties in the consolidated statements of operations and comprehensive income (loss). Unproved natural gas and oil property costs are transferred to proved natural gas and oil properties if the properties are subsequently determined to be productive or are assigned proved reserves. Unproved natural gas and oil properties are assessed periodically for impairment based on remaining lease terms, drilling results, reservoir performance, future plans to develop acreage, and other relevant factors.

Depreciation, Depletion and Amortization of Natural gas and oil Properties and Gathering Systems

The quantities of estimated proved natural gas and oil reserves are a significant component of our calculation of depreciation, depletion and amortization expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease, respectively.

Oil and natural gas and gathering system assets are depleted and depreciated using the units-of-production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved and unproved properties, the reserve base used to calculate depreciation and depletion is total proved reserves. For natural gas and oil development and gathering system costs, the reserve base used to calculate depletion and depreciation is proved developed reserves.

Depreciation, depletion and amortization rates are updated quarterly to reflect the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

Impairments

The carrying value of unproved and proved oil and natural gas properties and gathering system assets are reviewed for impairment whenever events indicate that the carrying amounts for those assets may not be recoverable. Such indicators include changes in our business plans, changes in commodity prices leading to unprofitable performance, and, for natural gas and oil properties, significant downward revisions of estimated proved reserve quantities or significant increases in the estimated development costs.

We compare expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the carrying value of the asset. If the expected undiscounted future cash flows, based on our estimates of (and assumptions regarding) future oil and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the carrying value of the asset, the carrying value is reduced to fair value. Fair value is generally calculated using the "Income Approach" based on estimated discounted net cash flows. Estimates of future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. In addition, such assumptions and estimates are reasonably likely to change in the future. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices and (iv) a market-based weighted average cost of capital rate.

We evaluate impairment of proved and unproved natural gas and oil properties on an area basis. On this basis, certain fields may be impaired because they are not expected to recover their entire carrying value from future net cash flows. The basis for future depletion, depreciation, amortization, and accretion will take into account the reduction in the value of the asset as a result of any accumulated impairment losses.

When circumstances indicate that the gathering system properties may be impaired, Epsilon compares expected undiscounted future cash flows related to the gathering system to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach, which considers estimated discounted future cash flows.

Derivative Financial Instruments

Derivative financial instruments are used to hedge exposure to changes in commodity prices arising in the normal course of business. The principal derivatives that may be used are commodity price swap and collar contracts. The use of these instruments is subject to policies and procedures as approved by the Board. Derivative financial instruments are not traded for speculative purposes. No derivative contracts have been designated as cash flow hedges for accounting purposes. Derivative financial instruments are initially recognized at cost, if any, which approximates fair value. Subsequent to initial recognition, derivative financial instruments are recognized at fair value. The derivatives are valued on a mark-to-market valuation, and the gain or loss on re-measurement to fair value is recognized through the consolidated statements of operations and comprehensive income (loss). The estimated fair value of derivative instruments requires substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity, and credit risk. The values reported in Epsilon's financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The counterparties to our derivative instruments are not known to be in default on their derivative positions. However, we are exposed to credit risk to the extent of nonperformance by the counterparty in the derivative contracts. We believe credit risk is minimal and do not anticipate such nonperformance by such counterparties.

Asset Retirement Obligations ("ARO")

We recognize asset retirement obligations under ASC 410, Asset Retirement and Environmental Obligations. ASC 410 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. For our upstream properties, these obligations consist of estimated future costs associated with the plugging and abandonment of natural gas and oil wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. For our gathering system, these obligations consist of estimated future costs associated with the removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the natural gas and oil or gathering system asset. The initial recognition of an ARO fair value requires that management make numerous assumptions regarding such factors as the amounts and timing of settlements; the credit-adjusted risk-free discount rate; and the inflation rate. In periods subsequent to the initial measurement of an ARO, period-to-period changes are recognized in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the natural gas and oil property or gathering system asset.

Income Taxes

Tax regulations and legislation in the U.S. and Canada are subject to change and differing interpretations requiring judgment. We compute income taxes using the asset-and-liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amounts of existing assets and liabilities, as well as loss and tax credit carryforwards. Changes in tax rates and laws are recognized in income in the period such changes are enacted.

We establish a valuation allowance if, based on available evidence, it is more likely than not that some or all of the deferred tax assets will not be realized. We consider all positive and negative evidence, including historical operating results, the existence of cumulative losses, estimates of future operating income, and the reversal of existing taxable temporary differences in assessing the need for a valuation allowance. Income tax filings are subject to audits and re-assessments. Changes in facts, circumstances, and interpretations of the standards may result in a material increase or decrease in our provision for income taxes.

Recently Issued Accounting Standards

See Note 3 Summary of Significant Accounting Policies in Notes to the Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Our earnings and cash flow are significantly affected by changes in the market price of commodities. The prices of oil and natural gas can fluctuate widely and are influenced by numerous factors such as demand, production levels, and world political and economic events and the strength of the U.S. dollar relative to other currencies. Should the price of oil or natural gas decline substantially, the value of our assets could fall dramatically, impacting our future options and exploration and development activities, along with our gas gathering system revenues. In addition, our operations are exposed to market risks in the ordinary course of our business, including interest rate and certain exposure as well as risks relating to changes in the general economic conditions in the United States.

Gathering System Revenue Risk

The Auburn Gas Gathering System lies within the Marcellus Basin with historically high levels of recoverable reserves and low cost of production. We believe that a short-term low commodity price environment will not significantly impact the reserves produced and thus the revenue of our gas gathering system.

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100-basis-point change in the interest rate on the outstanding balance under our credit agreement. The credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to three months. To the extent that the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not affect results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will affect future results of operations and cash flows.

At December 31, 2022 and 2021, the outstanding principal balance under the credit agreement was nil.

Derivative Contracts

The Company's financial results and condition depend on the prices received for natural gas production. Natural gas prices have fluctuated widely and are determined by economic and political factors. Supply and demand factors, including weather, general economic conditions, the ability to transport the gas to other regions, as well as conditions in other natural gas regions, impact prices. Epsilon has established a hedging strategy and may manage the risk associated with changes in commodity prices by entering into various derivative financial instrument agreements and physical contracts. Although these commodity price risk management activities could expose the Company to losses or gains, entering into these contracts helps to stabilize cash flows and support the Company's capital spending program.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Our consolidated balance sheets as of December 31, 2022 and 2021, and the consolidated statements of operations and comprehensive income, changes in shareholders' equity and cash flows for years ended December 31, 2022 and 2021 included in this annual report have been prepared in accordance with U.S. GAAP.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Epsilon Energy Ltd.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Epsilon Energy, Ltd (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of operations and comprehensive income, changes in shareholders' equity, and cash flows for each of 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 financial position of the Company at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of 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 that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

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

Houston, Texas
March 23, 2023

EPSILON ENERGY LTD.

Consolidated Balance Sheets

	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 45,236,584	$ 26,497,305
Accounts receivable	7,201,386	4,596,931
Fair value of derivatives	1,222,090	—
Prepaid income taxes	1,140,094	—
Other current assets	632,154	569,870
Operating lease right-of-use assets	31,383	—
Total current assets	55,463,691	31,664,106
Non-current assets		
Property and equipment:		
Oil and gas properties, successful efforts method		
Proved properties	148,326,265	138,032,413
Unproved properties	18,169,157	21,700,926
Accumulated depletion, depreciation, amortization and impairment	(107,729,293)	(102,480,972)
Total oil and gas properties, net	58,766,129	57,252,367
Gathering system	42,639,001	42,475,086
Accumulated depletion, depreciation, amortization and impairment	(34,500,740)	(33,443,949)
Total gathering system, net	8,138,261	9,031,137
Land	637,764	637,764
Buildings and other property and equipment, net	286,035	309,102
Total property and equipment, net	67,828,189	67,230,370
Other assets:		
Restricted cash	570,363	568,118
Total non-current assets	68,398,552	67,798,488
Total assets	$ 123,862,243	$ 99,462,594
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable trade	$ 1,695,353	$ 1,189,905
Gathering fees payable	935,012	963,546
Royalties payable	2,223,043	1,853,508
Income taxes payable	—	1,098,425
Accrued capital expenditures	41,694	1,016,830
Accrued compensation	598,351	343,348
Other accrued liabilities	690,655	754,779
Fair value of derivatives	—	239,824
Asset retirement obligations	—	85,207
Operating lease liabilities	35,299	—
Total current liabilities	6,219,407	7,545,372
Non-current liabilities		
Asset retirement obligations	2,780,237	2,748,449
Deferred income taxes	10,617,394	9,905,440
Total non-current liabilities	13,397,631	12,653,889
Total liabilities	19,617,038	20,199,261
Commitments and contingencies (Note 10)		
Shareholders' equity		
Preferred shares, no par value, unlimited shares authorized, none issued or outstanding	—	—
Common shares, no par value, unlimited shares authorized and 23,117,144 issued and outstanding at December 31, 2022 and 24,202,218 issued and 23,668,203 shares outstanding at December 31, 2021	123,904,965	131,815,739
Treasury shares, at cost, 0 at December 31, 2022 and 534,015 at December 31, 2021	—	(2,423,007)
Additional paid-in capital	9,856,229	8,835,203
Accumulated deficit	(39,290,540)	(68,783,207)
Accumulated other comprehensive income	9,774,551	9,818,605
Total shareholders' equity	104,245,205	79,263,333
Total liabilities and shareholders' equity	$ 123,862,243	$ 99,462,594

The accompanying notes are an integral part of these consolidated financial statements

EPSILON ENERGY LTD.

Consolidated Statements of Operations and Comprehensive Income

	Year ended December 31, 2022	2021
Revenues from contracts with customers:		
Gas, oil, NGL, and condensate revenue	$ 61,877,197	$ 34,538,167
Gas gathering and compression revenue	8,085,512	7,865,825
Total revenue	69,962,709	42,403,992
Operating costs and expenses:		
Lease operating expenses	7,128,631	6,303,055
Gathering system operating expenses	2,287,763	2,321,329
Development geological and geophysical expenses	9,545	40,299
Depletion, depreciation, amortization, and accretion	6,438,511	6,627,016
Impairment expense	—	153,058
Gain on sale of oil and gas properties	(221,642)	(484,902)
General and administrative expenses:		
Stock based compensation expense	1,021,026	956,084
Other general and administrative expenses	6,325,412	5,875,732
Total operating costs and expenses	22,989,246	21,791,671
Operating income	46,973,463	20,612,321
Other income (expense):		
Interest income	452,877	38,865
Interest expense	(50,782)	(101,382)
Gain (loss) on derivative contracts	236,077	(4,482,909)
Other income (expense)	(99,469)	1,130
Other income (expense), net	538,703	(4,544,296)
Net income before income tax expense	47,512,166	16,068,025
Income tax expense	12,157,487	4,440,508
NET INCOME	$ 35,354,679	$ 11,627,517
Currency translation adjustments	(44,054)	(2,042)
NET COMPREHENSIVE INCOME	$ 35,310,625	$ 11,625,475
Net income per share, basic	$ 1.52	$ 0.49
Net income per share, diluted	$ 1.51	$ 0.49
Weighted average number of shares outstanding, basic	23,319,633	23,705,193
Weighted average number of shares outstanding, diluted	23,406,189	23,857,102

The accompanying notes are an integral part of these consolidated financial statements

EPSILON ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity

	Common Shares Issued		Treasury Shares		Additional	Accumulated Other Comprehensive	Accumulated	Total Shareholders'
	Shares	Amount	Shares	Amount	paid-in Capital	Income	Deficit	Equity
Balance at December 31, 2020	23,985,799	$ 131,730,401	—	$ —	$ 7,879,119	$ 9,820,647	$ (80,410,724)	$ 69,019,443
Net income	—	—	—	—	—	—	11,627,517	11,627,517
Stock-based compensation expenses	—	—	—	—	956,084	—	—	956,084
Buyback of common shares	—	—	(534,015)	(2,423,007)	—	—	—	(2,423,007)
Exercise of stock options	16,250	85,338	—	—	—	—	—	85,338
Vesting of shares of restricted stock	200,169	—	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	(2,042)	—	(2,042)
Balance at December 31, 2021	24,202,218	$ 131,815,739	(534,015)	$ (2,423,007)	$ 8,835,203	$ 9,818,605	$ (68,783,207)	$ 79,263,333
Net income	—	—	—	—	—	—	35,354,679	35,354,679
Dividends	—	—	—	—	—	—	(5,862,012)	(5,862,012)
Stock-based compensation expenses	—	—	—	—	1,021,026	—	—	1,021,026
Buyback of common shares	—	—	(982,500)	(6,234,879)	—	—	—	(6,234,879)
Retirement of treasury shares	(1,516,515)	(8,657,886)	1,516,515	8,657,886	—	—	—	—
Exercise of stock options	138,750	747,112	—	—	—	—	—	747,112
Vesting of shares of restricted stock	292,691	—	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	(44,054)	—	(44,054)
Balance at December 31, 2022	23,117,144	$ 123,904,965	—	$ —	$ 9,856,229	$ 9,774,551	$ (39,290,540)	$ 104,245,205

The accompanying notes are an integral part of these consolidated financial statements

EPSILON ENERGY LTD.

Consolidated Statements of Cash Flows

	Year ended December 31, 2022	Year ended December 31, 2021
Cash flows from operating activities:		
Net income	$ 35,354,679	$ 11,627,517
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	6,438,511	6,627,016
Impairment expense	—	153,058
Loss (gain) on derivative contracts	(236,077)	4,482,909
Gain on sale of oil and gas properties	(221,642)	(484,902)
Settlement (paid) received on derivative contracts	(1,225,837)	(4,243,085)
Settlement of asset retirement obligation	(118,260)	—
Stock-based compensation expense	1,021,026	956,084
Deferred income tax expense (benefit)	711,954	(197,412)
Changes in assets and liabilities:		
Accounts receivable	(2,604,455)	(679,643)
Other current assets	(58,368)	20,000
Accounts payable, royalties payable and other accrued liabilities	1,182,348	646,410
Income taxes payable	(2,238,519)	1,098,425
Net cash provided by operating activities	38,005,360	20,006,377
Cash flows from investing activities:		
Additions to unproved oil and gas properties	(310,211)	(148,862)
Additions to proved oil and gas properties	(7,562,502)	(4,435,945)
Additions to gathering system properties	(184,032)	(297,841)
Additions to land, buildings and property and equipment	(13,258)	(5,745)
Proceeds from sale of oil and gas properties	200,000	450,000
Prepaid drilling costs	—	379
Net cash used in investing activities	(7,870,003)	(4,438,014)
Cash flows from financing activities:		
Buyback of common shares	(6,234,879)	(2,423,007)
Exercise of stock options	747,112	85,338
Dividends	(5,862,012)	—
Net cash used in financing activities	(11,349,779)	(2,337,669)
Effect of currency rates on cash, cash equivalents and restricted cash	(44,054)	(2,042)
Increase in cash, cash equivalents and restricted cash	18,741,524	13,228,652
Cash, cash equivalents and restricted cash, beginning of period	27,065,423	13,836,771
Cash, cash equivalents and restricted cash, end of period	$ 45,806,947	$ 27,065,423
Supplemental cash flow disclosures:		
Income taxes paid	$ 13,669,000	$ 3,444,025
Interest paid	$ 68,328	$ 95,942
Non-cash investing activities:		
Change in unproved properties accrued in accounts payable and accrued liabilities	$ —	$ (65,000)
Change in proved properties accrued in accounts payable and accrued liabilities	$ (1,100,041)	$ (1,097,257)
Change in gathering system accrued in accounts payable and accrued liabilities	$ (20,118)	$ (25,399)
Asset retirement obligation asset additions and adjustments	$ 12,053	$ 33,234

The accompanying notes are an integral part of these consolidated financial statements

1. Description of Business

Epsilon Energy Ltd. (the "Company" or "Epsilon" or "we") was incorporated under the laws of the Province of Alberta, Canada on March 14, 2005. On October 24, 2007, the Company became a publicly traded entity trading on the Toronto Stock Exchange ("TSX") in Canada. On February 14, 2019, Epsilon's registration statement on Form 10 was declared effective by the United States Securities and Exchange Commission and on February 19, 2019, we began trading in the United States on the NASDAQ Global Market under the trading symbol "EPSN." Effective as of the close of trading on March 15, 2019, Epsilon voluntarily delisted its common shares from the TSX. Epsilon is a North American on-shore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves.

2. Basis of Preparation

Principles of Consolidation

The Company's consolidated financial statements include the accounts of the Company and its wholly owned subsidiary, Epsilon Energy USA, Inc. and its wholly owned subsidiaries, Epsilon Midstream, LLC, Epsilon Operating, LLC, Dewey Energy GP, LLC, Dewey Energy Holdings, LLC and Altolisa Holdings, LLC. With regard to the gathering system, in which Epsilon owns an undivided interest in the asset, proportionate consolidation accounting is used. All inter-company transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas reserves and related cash flow estimates used in impairment tests of oil and natural gas and gathering system properties, asset retirement obligations, accrued natural gas and oil revenues and operating expenses, accrued gathering system revenues and operating expenses, as well as the valuation of commodity derivative instruments. Actual results could differ from those estimates.

Reclassification

The consolidated financial statements for the prior periods include certain reclassifications that were made to conform to the current period presentation. Such reclassifications have no impact on previously reported consolidated financial position, results of operations or cash flows.

3. Summary of Significant Accounting Policies

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents include cash on hand and short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Restricted cash consists of amounts deposited to back bonds or letters of credit for potential well liabilities. The Company presents restricted cash with cash and cash equivalents in the Consolidated Statements of Cash Flows.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported in the Consolidated Balance Sheets to the total of the amounts in the Consolidated Statements of Cash Flows as of December 31, 2022 and 2021:

	December 31, 2022	December 31, 2021
Cash and cash equivalents	$ 45,236,584	$ 26,497,305
Restricted cash included in other assets	570,363	568,118
Cash, cash equivalents and restricted cash in the statement of cash flows	$ 45,806,947	$ 27,065,423

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are primarily from purchasers of oil and natural gas, counterparties to our financial instruments, and revenues earned for compression and gathering services. Both oil and natural gas receivables are generally collected within 30 days after the end of the month. Compression and gathering receivables are generally collected within 60 days after the end of the month.

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. We estimate the allowance for doubtful accounts through various procedures, including review of our trade receivable balances by counterparty, assessing economic events and conditions, our historical experience with counterparties, the counterparty's financial condition and the amount and age of past due accounts. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted.

Our allowance for doubtful accounts was nil as of December 31, 2022 and 2021.

Oil and Natural Gas Properties

Epsilon accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Oil and natural gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and natural gas properties. Lease delay rentals are expensed as incurred.

Oil and natural gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether Epsilon has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized (see Note 4).

Depreciation, depletion and amortization of the cost of proved oil and natural gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves.

When circumstances indicate that proved (developed and undeveloped) oil and natural gas properties may be impaired, Epsilon compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the carrying value of the asset. If the expected undiscounted future cash flows, based on Epsilon's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the carrying value of the asset, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach which considers estimated discounted future cash flows.

Gas Gathering System Properties

Epsilon's 35% portion of asset development costs are capitalized when incurred. All other costs are expensed.

Depreciation, depletion and amortization of the cost of gathering system properties is calculated using the unit-of- production method. The reserve base used to calculate depreciation, depletion and amortization for the gathering system includes only proved Pennsylvania, natural gas developed reserves.

When circumstances indicate that the gathering system properties may be impaired, Epsilon compares expected undiscounted future cash flows related to the gathering system to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach, which considers estimated discounted future cash flows.

Revenue Recognition

Revenues are comprised primarily of sales of natural gas and to a much lesser degree crude oil and NGLs, along with the revenue generated from the Company's ownership interest in the gas gathering system in the Auburn field in Northeastern Pennsylvania.

Revenue recognition is evaluated through the following five steps: (i) identification of the contract, or contracts, with a customer; (ii) identification of the performance obligations in the contract; (iii) determination of the transaction price; (iv) allocation of the transaction price to the performance obligations in the contract; and (v) recognition of revenue when or as a performance obligation is satisfied.

Accounting Policies

Revenue is recognized when performance obligations under the terms of a contract with a customer are satisfied. The Company recognizes upstream revenue at the point in time when control has been transferred to the customer, generally at the time natural gas reaches an agreed-upon delivery point and collectability is reasonably assured. Upstream revenue is generally based upon a fixed price, based on a market index, and is measured as the amount of consideration the Company expects to receive in exchange for the transferring of the natural gas. The services provided by the gas gathering system take place continuously and as a practical expedient, the revenues are recognized monthly for the volumes that are processed and transported for the upstream producers during that period of time. Revenue for the services performed are based on the rates outlined in the cost of service agreement that governs all volumes gathered and processed by the system. The gathering rates are adjusted, and fixed annually. Typically, the Company sells its natural gas directly to customers, under agreements with payment terms less than 30 days after delivery and 60 days on the revenue generated by the gas gathering system.

Natural Gas Revenues

The Company's natural gas purchase contracts are generally structured such that Epsilon commits and dedicates for sale its proportionate share of natural gas production per day to a purchaser. Natural gas is sold at a percentage of index prices of each component, less any stated deductions. Control transfers at the delivery point specified in the contract, which typically is stated as the inlet of the third-party sales transportation pipeline. The Company recognizes revenue proportionate to its entitled share of volumes sold. Currently, the vast majority of Epsilon's natural gas production comes from the Marcellus Field in Northeastern Pennsylvania.

Epsilon uses a third-party service for its natural gas marketing. In this capacity, the third-party is responsible for carrying out marketing activities such as submission of nominations, receipt of payments, submission of invoices and negotiation of contracts. Commissions payable to the third-party broker for these services are treated as lease operating expenses in the financial statements.

Gas Gathering System Revenue

The Company has a 35% ownership interest in the Auburn Gas Gathering System ("Auburn GGS"). This system aggregates the natural gas from the various pads in the field and transports the natural gas to the inlet of the Auburn compression facility where it is dehydrated, compressed and injected into Tennessee Gas Pipeline. The gathering and compression services operate under fee-based contracts. The producers in the area served by the gathering system pay fees to the system owners based on the services provided to them in getting their share of the gas production to the third-party sales transmission point. Revenue is recognized over time as the services are provided.

Oil and Other Liquids Revenue

The source of the Company's oil and other liquids revenue is its ownership interest in wells in Oklahoma. The Company does not operate the wells and has elected not to receive its proportionate share of the production. As such, under the Joint Operating Agreement, the operators have control of the marketing of this production at current market prices and remits our net revenue interest less taxes and fees on a monthly basis. The Company recognizes revenue with a monthly accrual of its proportionate share of volumes produced at an estimated market price.

Accounts Receivable and Other

Oil, natural gas liquid and natural gas receivables consist of amounts due from purchasers for commodity sales from our revenue interest in the leases in Northwestern Pennsylvania and Oklahoma. Payments from purchasers are typically due by the last day of the month following the month of delivery. Gathering fee revenue consists of fees due from the operator of the Auburn GGS, as an agent for the Company fulfilling the operations of the gathering system. Payments from the operator are typically due 60 days from the last day of the month of transmission. The Company's operations do not result in any contract assets or liabilities on the accompanying consolidated balance sheets.

Buildings and Other Property and Equipment

Buildings are depreciated on a straight-line basis over the estimated useful life of the property, 30 years.

Other property and equipment consists of computer hardware and software, and furniture and fixtures. Other property and equipment is generally depreciated on a straight-line basis over the estimated useful lives of the property and equipment, which range from 3 years to 7 years.

Financial Instruments and Fair Value

Epsilon's financial instruments consist of cash, cash equivalents, restricted cash, commodity derivative contracts, accounts receivable, accounts payable, and long-term debt.

Our financial instruments that are accounted for at fair value consist of commodity derivatives.

The Company classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3—Valuations in this level are those with inputs for the asset or liability that are not based on observable market data. The Company makes its own assumptions about how market participants would price the assets and liabilities.

Cash, cash equivalents, and restricted cash are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. These financial instruments are therefore designated as Level 1 within the valuation hierarchy.

Commodity derivative instruments consist of fixed-price swaps, and basis swap contracts for natural gas. The Company's derivative contracts are valued based on an income approach. The model considers various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy.

Derivative Instruments

The Company enters into derivative contracts to hedge price risk associated with a portion of natural gas production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated, which has, and could, result in over-hedged volumes. Natural gas production is primarily sold under market sensitive contracts which are typically priced at a differential to the NYMEX or the published natural gas index prices for the producing area due to the natural gas quality and the proximity to major consuming markets. Our derivative transactions have included the following:

- Fixed-price swaps—where a fixed-price is received for production and a variable market price is paid to the contract counterparty.

- Basis swap contracts—which guarantee a specified price differential between the price at Henry Hub and our physical pricing points. If the settled price differential is greater than the swapped basis, then we receive a payment from the counterparty in the amount of the difference between the two. If the settled price differential is less than the swapped basis, then we make a payment to the counterparty for the difference between the two.

- Two-way collar contracts—which guarantee a specified price range for NYMEX by using the proceeds of selling a call option at a specified strike price (the "Ceiling") to finance the purchase of a put option at a specified strike price (the "Floor").

Derivative instruments are recorded on the consolidated balance sheets at fair value as either current or non-current assets or liabilities based on their anticipated settlement date. Gains or losses on derivative contracts are recorded as gain (loss) on commodity contracts in the consolidated statements of operations and comprehensive income. Hedge accounting is not used for our derivative assets and liabilities.

Asset Retirement Obligations

The Company records a liability for asset retirement obligations at fair value in the period in which the liability is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method of the asset's useful life. Recognized asset retirement obligations relate to the plugging and abandonment of oil and natural gas wells and decommissioning of the gas gathering system. Management reviews the estimates of the timing of well abandonments as well as the estimated plugging and abandonment costs, which are discounted at the credit adjusted risk free rate. These adjustments are recorded to the asset retirement obligations with an offsetting change to oil and gas properties. An ongoing accretion expense is recognized for changes in the value of the liability as a result of the forecast inflation due to the passage of time, which is recorded in depreciation, depletion, amortization, and accretion expense in the consolidated statements of operations and comprehensive income.

Concentrations of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative contracts. Exposure to credit risk associated with these instruments is controlled by (i) placing assets and other financial interests with credit-worthy financial institutions, (ii) maintaining policies over credit extension that include the evaluation of customers' financial condition and monitoring paying history, although the Company does not have collateral requirements and (iii) netting derivative assets and liabilities for counterparties with a legal right of offset.

At December 31, 2022 and 2021, the cash and cash equivalents were primarily concentrated in one financial institution the U.S. We currently have $7.2 million in excess of the federally insured limits. The Company periodically assesses the financial condition of these institutions and believe that any possible credit risk is minimal.

For the years ended December 31, 2022 and 2021, the Company had three customers that accounted for 95.7% and 85.9%, respectively, of the total trade accounts receivable.

Geographic Locations of Operations

Approximately 91% and 93% of our production during fiscal 2022 and 2021, respectively was derived from natural gas production and gathering system revenues in the state of Pennsylvania. As a result of this geographic concentration, we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas.

Income Taxes

Deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. Epsilon assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate (see Note 9).

Foreign Currency Transactions

Even though the Canadian dollar is the functional currency of Epsilon Energy Ltd. (the parent entity), the United States dollar is the reporting currency for all of Epsilon's consolidated subsidiaries. Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period. Gains and losses on translation of balances denominated in Canadian dollars are included in accumulated other comprehensive income.

Stock-Based Compensation

The Company mainly estimates the fair value of all stock options awarded to employees and directors using the Black-Scholes option pricing model. Other models are used for options with more complex vesting criteria. Compensation expense and a corresponding increase to additional paid-in capital are recorded over the vesting period based on the fair value of the options granted using a graded vesting approach. When stock options are exercised for common shares, consideration paid by the stock option holders and additional paid-in capital associated with the stock options are recorded. The Company estimates a forfeiture rate and adjusts the corresponding expense each period based on an updated forfeiture estimate (see Note 6).

The Company has issued time-based restricted stock and performance share units ("PSU") to employees and directors of the Company. The fair value of the time-based restricted stock is determined using the fair value of the Company's common shares on the date of grant. The fair value of the PSUs is determined by the performance requirements. Based on the performance requirements, either the fair value of the Company's common shares on the date of grant, or a Monte Carlo valuation is used to determine fair value of the shares at the date of the grant. These awards vest ratably over a three-year period. Compensation expense and a corresponding increase to additional paid in capital are recorded over the vesting period.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)", which significantly changed accounting for leases by requiring that lessees recognize a right of use asset and a related lease liability representing the obligation to make lease payments, for all lease transactions with terms greater than one year. Additional disclosures about an entity's lease transactions are also required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant, or equipment (an identified asset) for a period of time in exchange for consideration." The Company adopted ASU 2016-02 for the year beginning in January 2022. We have chosen the transition using the comparative report at adoption method of applying the provisions of the new standard at the beginning of the period of adoption instead of the earliest comparative period presented in the consolidated financial statements. There was no material effect from the adoption.

The Company leases office space to be used for general, administrative, and executive offices with terms typically ranging from five to seven years, subject to certain renewal options as applicable. The Company considers renewal or termination options that are reasonably certain to be exercised in the determination of the lease term and initial measurement of lease liabilities and right-of-use assets. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term. Interest expense for finance leases is incurred based on the carrying value of the lease liability. Leases with an initial term of 12 months or less are not recorded on the Company's Consolidated Balance Sheets and lease agreements with lease and non-lease components are generally accounted for as a single lease component.

The Company determines whether a contract is, or contains, a lease at inception of the contract and whether that lease meets the classification criteria of a finance or operating lease. When available, the Company uses the rate implicit in the lease to discount lease payments to present value; however, most of the Company's leases do not provide a readily determinable implicit rate. Therefore, the Company must discount lease payments based on an estimate of its incremental borrowing rate based on prevailing financial market conditions at the later of date of adoption or lease commencement, credit analysis of comparable companies and management judgments to determine the present values of its lease payments. (see Note 10).

Joint Interests

The majority of the Company's oil and natural gas exploration, development and production activities, and the gathering system, are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such jointly controlled assets.

Recently Issued Accounting Standards

The Company, an emerging growth company ("EGC"), has elected to take advantage of the benefits of the extended transition period provided for in Section 7(a)(2)(B) of the Securities Act, for complying with new or revised accounting standards which allows the Company to defer adoption of certain accounting standards until those standards would otherwise apply to private companies.

In December 2019, the Financial Accounting Standards Board ("FASB") issued ASU 2019-12, "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes," which simplifies the accounting for income taxes by removing certain exceptions to the general principles in Topic 740, Income Taxes. The Company adopted ASU 2019-12 for the year beginning in January 2021. There was no immediate impact from the adoption.

In June 2016 the FASB issued ASU 2016-13, "Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments", which removes the thresholds that companies apply to measure credit losses on financial instruments measured at amortized cost, such as loans, receivables, and held-to-maturity debt securities. Under current U.S. GAAP, companies generally recognize credit losses when it is probable that the loss has been incurred. The revised guidance will remove all recognition thresholds and will require companies to recognize an allowance for credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost that the company expects to collect over the instrument's contractual life. ASU 2016-13 is effective for fiscal years beginning after December 15, 2022, and interim periods within those fiscal years, and must be applied retrospectively. Early adoption is permitted. Epsilon is currently assessing the expected impact and will adopt ASU 2016-13 as of January 1, 2023. We do not expect a material effect from the adoption of this ASU.

4. Property and Equipment

The following table summarizes the Company's property and equipment at December 31, 2022 and 2021:

	December 31, 2022	December 31, 2021
Property and equipment:		
Oil and gas properties, successful efforts method		
Proved properties	$ 148,326,265	$ 138,032,413
Unproved properties	18,169,157	21,700,926
Accumulated depletion, depreciation, amortization and impairment	(107,729,293)	(102,480,972)
Total oil and gas properties, net	58,766,129	57,252,367
Gathering system	42,639,001	42,475,086
Accumulated depletion, depreciation, amortization and impairment	(34,500,740)	(33,443,949)
Total gathering system, net	8,138,261	9,031,137
Land	637,764	637,764
Buildings and other property and equipment, net	286,035	309,102
Total property and equipment, net	$ 67,828,189	$ 67,230,370

Property Sale

In April 2022, the Company completed a well bore only sale and conveyance and partial release of oil and gas leases in Oklahoma for $200,000. In December 2021, the Company completed the sale of its shallow rights leases and wells in Oklahoma for $450,000.

Property Impairment

Epsilon performs a quantitative impairment test whenever events or changes in circumstances indicate that an asset group's carrying amount may not be recoverable. When indicators of impairment are present, the Company first compares expected future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount to the estimated fair values is required. This is determined based on discounted cash flow techniques using significant assumptions including production volumes, future commodity prices, and a market-specific weighted average cost of capital which are affected by expectations about future market and economic conditions. Additionally, GAAP requires that if an exploratory well is determined not to have found proved reserves, the costs incurred, net of any salvage value, are charged to expense. For unproved properties, such as leasehold, expected current and future market prices for similar assets are considered relative to carrying values in evaluating impairment.

No impairment was recorded for the year ended December 31, 2022. For the year ended December 31, 2021, the Company recognized dry hole costs of $0.15 million.

5. Revolving Line of Credit

The Company has a senior secured credit facility which includes a total commitment of up to $100 million. The effective borrowing base is $30 million, which is subject to semi-annual redetermination. There are currently no borrowings under the facility. If we decide to access the facility, depending on the level of borrowing, we might need to increase our hedging activity. Borrowings from the Facility may be used for the acquisition and development of oil and gas properties, investments in cash flow generating assets complimentary to the production of oil and gas, and for letters of credit and other general corporate purposes. Upon each advance, interest is charged at the highest of a) the Prime Rate, or b) the sum of the Federal Funds Rate plus 0.5%, plus an applicable margin (0.25%-1.25%, based on percentage utilization on the facility).

The facility matures on March 1, 2024.

Effective April 6, 2021, the agreement was amended to extend the maturity date to March 1, 2024. In addition, the agreement was amended to include a *Benchmark Replacement* definition and transition plan to be used at such time when the LIBOR rate is discontinued.

On February 10, 2023, Epsilon Energy USA entered into the Ninth Amendment of the Credit Agreement. The borrowing base was increased to $30 million. LIBOR was removed as a reference option in the calculation of interest. Hedging requirements were amended to be between 0%-62.5% of the 24-month projected production volumes, based on percentage utilization on the facility. Also, cash distributions to the parent company (Epsilon Energy Ltd.) were allowed if the facility is < 80% utilized and the leverage ratio (total debt / income adjusted for interest, taxes and non-cash amounts) is less than 2.

The bank has a first priority security interest in the tangible and intangible assets of Epsilon Energy USA, Inc. to secure any outstanding amounts under the agreement. Under the terms of the agreement, the Company must maintain the following covenants:

- Interest coverage ratio greater than 3 (income adjusted for interest, taxes and non-cash amounts / cash interest expense)

- Current ratio greater than 1 (current assets / current liabilities)

- Leverage ratio less than 3.5 (total debt / income adjusted for interest, taxes and non-cash amounts)

We were in compliance with the financial covenants of the agreement as of December 31, 2022.

6. Shareholders' Equity

(a) Authorized shares

The Company is authorized to issue an unlimited number of common shares with no par value and an unlimited number of Preferred Shares with no par value.

(b) Purchases of Equity Shares

Commencing on March 8, 2022, we implemented a plan to repurchase our issued and outstanding common shares and to return capital to our shareholders. We used cash on hand to fund these repurchases. During the year ended December 31, 2022, we repurchased 982,500 common shares of the maximum of 1,183,410 authorized for repurchase and spent $6,234,879 under the plan. The repurchased stock had an average price of $6.32 per share (excluding commissions) and was subsequently retired during the year ended December 31, 2022.

In 2023, we repurchased 190,700 common shares at an average price of $5.82 per share (excluding commissions) before the plan terminated on March 7, 2023.

Commencing on January 1, 2021, we implemented a plan to repurchase our issued and outstanding common shares. The plan terminated on December 31, 2021. We used cash on hand to fund these repurchases. During the year ended December 31, 2021, we repurchased 534,015 common shares of the maximum of 1,193,000 authorized for repurchase and spent $2,423,007 under the plan. The repurchased stock had an average price of $4.51 per share (excluding commissions) and was subsequently retired during the year ended December 31, 2022.

On March 9, 2023, the Board of Directors authorized a new share repurchase program of up to 2,292,644 common shares, representing 10% of the outstanding common shares of Epsilon, for an aggregate purchase price of not more than US $15.0 million. The program is pursuant to a normal course issuer bid and will be conducted in accordance with Rule 10b-18 under the Exchange Act. The program will commence on March 27, 2023 and end on March 26, 2024, unless the maximum amount of common shares is purchased before then or Epsilon provides earlier notice of termination.

(c) **Equity Incentive Plan**

Epsilon's board of directors (the "Board") adopted the 2020 Equity Incentive Plan (the "2020 Plan") on July 22, 2020 subject to approval by Epsilon's shareholders at Epsilon's 2020 Annual General and Special Meeting of shareholders, which occurred on September 1, 2020 (the "Meeting"). Shareholders approved the 2020 Plan at the Meeting. Following Epsilon's listing on the NASDAQ Global Market, the Board determined that it is in the best interest of the shareholders to approve a new incentive plan that is compliant with U.S. public company equity plan rules and practices that would replace Epsilon's Amended and Restated 2017 Stock Option Plan (including its predecessors) and the Share Compensation Plan (collectively referred to as the "Predecessor Plans"). No further awards will be granted under the Predecessor Plans.

The 2020 Plan provides for incentive compensation in the form of stock options, stock appreciation rights, restricted stock and stock units, performance shares and units, other stock-based awards and cash-based awards. Under the 2020 Plan, Epsilon is authorized to issue up to 2,000,000 common shares.

Restricted Stock Awards

For the year ended December 31, 2022, 289,231 common shares of Restricted Stock with a weighted average market price at grant date of $6.28 were awarded to the Company's officers, employees, and board of directors. For the year ended December 31, 2021, 48,000 common shares of Restricted Stock with a weighted average market price at grant date of $5.04 were awarded to the Company's board of directors. These shares vest over a three or four-year period, with an equal number of shares being issued per period on the anniversary of the award resolution. The vesting of the shares is contingent on the individuals' continued employment or service. The Company determined the fair value of the granted Restricted Stock-based on the market price of the common shares of the Company on the date of grant.

The following table summarizes restricted stock for the years ended December 31, 2022 and 2021:

	Year ended December 31, 2022		Year ended December 31, 2021	
	Number of Restricted Shares Outstanding	Weighted Average Remaining Life (years)	Number of Restricted Shares Outstanding	Weighted Average Remaining Life (years)
Balance non-vested Restricted Stock at beginning of period	166,002	1.38	290,070	1.60
Granted	289,231	1.86	48,000	1.67
Vested	(157,023)	—	(137,668)	—
Forfeited	—	—	(34,400)	—
Balance non-vested Restricted Stock at end of period	298,210	1.74	166,002	1.38

Stock compensation expense for the granted Restricted Stock is recognized over the vesting period. Stock compensation expense recognized during the year ended December 31, 2022 was $776,939 (for the year ended December 31, 2021, $554,249).

At December 31, 2022, the Company had unrecognized stock-based compensation related to these shares of $1,668,564 to be recognized over a weighted average period of 1.55 years.

Performance Share Unit Awards ("PSU")

The Company grants PSUs, which are paid in stock to certain key employees. The PSUs will vest on the last day of the performance period. The number of PSUs that will ultimately vest is based on two performance targets as follows:

- The targets for the PSUs are based on (i) the relative total stockholder return ("TSR") percentile ranking and (ii) the relative cash flow per debt adjusted share – growth ("CFDAS Growth") percentile ranking of the Company, each as compared to the Company's peer group as specified in the award agreement during the applicable one-year performance period ending on December 31.

- Cash Flow per Debt Adjusted Share ("CFDAS") is defined as EBITDA (earnings before interest, taxes, depreciation and amortization) divided by the sum of the 1) the total debt plus the value of preferred stock minus cash and the amount of dividends paid for the year divided by the share price at the end of the year; and 2) the actual share count at year end.

- The vesting of each PSU Award will be based 50% on TSR performance and 50% based on CFDAS Growth performance.

- The recipient of the award must be employed with the Company at the time of vesting.

The number of shares ultimately issued under these awards can range from zero to 200% of target award amounts at the discretion of the Compensation Committee of the Board of Directors. During the year ended December 31, 2022, a total of 31,667 common shares were vested and issued.

The following table summarizes PSUs for the years ended December 31, 2022 and 2021:

	Year ended December 31, 2022		Year ended December 31, 2021	
	Number of Performance Shares Outstanding	Weighted Average Remaining Life (years)	Number of Performance Shares Outstanding	Weighted Average Remaining Life (years)
Balance non-vested PSUs at beginning of period	151,500	3.84	193,167	1.60
Granted	—	—	20,834	5.04
Vested	(135,667)	—	(62,501)	—
Balance non-vested PSUs at end of period	15,833	1.00	151,500	3.84

Stock compensation expense for the granted PSUs is recognized over the vesting period. Stock compensation expense recognized during the year ended December 31, 2022 related to PSUs was $244,087 (for the year ended December 31, 2021, $401,835).

At December 31, 2022, the Company had unrecognized stock-based compensation related to these shares of $63,328 to be recognized over a weighted average period of 0.63 years (at December 31, 2021: $310,790 over 1.01 years).

Stock Options

As of December 31, 2022, the Company had outstanding stock options covering 70,000 common shares at an overall average exercise price of $5.03 per common share to directors, officers, and employees of the Company and its subsidiaries. These 70,000 options have a weighted average expected remaining term of approximately 1.05 years.

The following table summarizes stock option activity for the years ended December 31, 2022 and 2021:

	Year ended December 31, 2022		Year ended December 31, 2021	
Exercise price in US$	Number of Options Outstanding	Weighted Average Exercise Price	Number of Options Outstanding	Weighted Average Exercise Price [1]
Balance at beginning of period	218,750	$ 5.28	245,000	$ 5.27
Exercised	(138,750)	$ 5.38	(16,250)	$ 5.25
Expired/Forfeited	(10,000)	$ 5.51	(10,000)	$ 5.50
Balance at period-end	70,000	$ 5.03	218,750	$ 5.28
Exercisable at period-end	70,000	$ 5.03	218,750	$ 5.28

At December 31, 2022, the Company had unrecognized stock-based compensation related to these options of nil (for the year ended December 31, 2021: nil). The aggregate intrinsic value at December 31, 2022 was $112,000 (at December 31, 2021: nil).

During the years ended December 31, 2022 and 2021, the Company awarded no stock options.

The following table summarizes information for stock options outstanding at December 31, 2022:

Exercise Price	Number of Options Outstanding	Number of Options Exercisable	Option Pricing Model Valuations	Weighted Average Remaining Contractual Life (in years)
As of December 31, 2022				
$5.03	70,000	70,000	$ 165,185	1.05
Total	70,000	70,000	$ 165,185	1.05

The value of the options was recorded as stock-based compensation expense, with an offsetting amount to additional paid-in capital based on the vesting terms. Stock-based compensation for the options, for the years ended December 31, 2022 was nil (for the year ended December 31, 2021: nil).

7. Revenue Recognition

Revenues are comprised primarily of sales of natural gas along with the revenue generated from the Company's ownership interest in the gas gathering system in the Auburn field in Northeastern Pennsylvania. Also included to a much lesser degree is natural gas, crude oil and NGLs from Oklahoma.

Overall, product sales revenue generally is recorded in the month when contractual delivery obligations are satisfied, which occurs when control is transferred to the Company's customers at delivery points based on contractual terms and conditions. In addition, gathering and compression revenue generally is recorded in the month when contractual service obligations are satisfied, which occurs as control of those services is transferred to the Company's customers.

The following table details revenue for the years ended December 31, 2022 and 2021:

	Year Ended December 31,	
	2022	2021
Operating revenue		
Natural gas	$ 56,948,734	$ 31,708,185
Natural gas liquids	1,733,130	1,053,486
Oil and condensate	3,195,333	1,776,496
Gathering and compression fees	8,085,512	7,865,825
Total operating revenue	$ 69,962,709	$ 42,403,992

Product Sales Revenue

The Company enters into contracts with third party purchasers to sell its natural gas, oil, NGLs and condensate production. Under these product sales arrangements, the sale of each unit of product represents a distinct performance obligation. Product sales revenue is recognized at the point in time that control of the product transfers to the purchaser based on contractual terms which reflect prevailing commodity market prices. To the extent that marketing costs are incurred by the Company prior to the transfer of control of the product, those costs are included in lease operating expenses on the Company's consolidated statements of operations.

Settlement statements for product sales, and the related cash consideration, are generally received from the purchaser within 30 days. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the natural gas, oil, NGLs, or condensate. Estimated revenue due to the Company is recorded within the receivables line item on the accompanying consolidated balance sheets until payment is received.

Gas Gathering and Compression Revenue

The Company also provides natural gas gathering and compression services through its ownership interest in the gas gathering system in the Auburn field. For the provision of gas gathering and compression services, the Company collects its share of the gathering and compression fees per unit of gas serviced and recognizes gathering revenue over time using an output method based on units of gas gathered.

The settlement statement from the operator of the Auburn GGS is received two months after transmission and compression has occurred. As a result, the Company must estimate the amount of production that was transmitted and compressed within the system. Estimated revenue due to the Company is recorded within the receivables line item on the accompanying consolidated balance sheets until payment is received.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts on a case-by-case basis once there is evidence that collection is not probable. At December 31, 2022, there were no accounts for which collection was not probable.

The following table details accounts receivable as of December 31, 2022 and 2021:

	December 31, 2022	December 31, 2021
Accounts receivable		
Natural gas and oil sales	$ 5,696,419	$ 2,996,344
Joint interest billing	20,454	60,134
Gathering and compression fees	1,483,956	1,539,976
Other	557	477
Total accounts receivable	$ 7,201,386	$ 4,596,931

8. Accumulated Other Comprehensive Income

Accumulated other comprehensive income includes certain transactions that have generally been reported in the consolidated statements of changes in shareholders' equity. The activity in Accumulated Other Comprehensive Income during the years ended December 31, 2022 and 2021 consisted of the following:

	Year Ended December 31,	
	2022	2021
Balance at beginning of period	$ 9,818,605	$ 9,820,647
Translation (loss) gain	(44,054)	(2,042)
Balance at end of period	$ 9,774,551	$ 9,818,605

9. Income Taxes

Net income (loss) before income taxes is as follows for the periods indicated:

	Year ended December 31,	
	2022	2021
Foreign	$ (700,255)	$ (571,646)
U.S.	48,212,421	16,639,671
	$ 47,512,166	$ 16,068,025

We file a federal income tax return in the United States, Canada, and various state and local jurisdictions.

We believe that we have appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's tax returns are open to audit under the statute of limitations for the years ending December 31, 2018 through December 31, 2022.

The following tables present the Company's current and deferred tax expense (benefit) for the periods indicated:

	Year ended December 31, 2022	2021
Current:		
Federal	$ 7,788,302	$ 3,152,866
State	3,657,231	1,485,054
Total current income tax expense	11,445,533	4,637,920
Deferred:		
Federal	1,587,935	84,631
State	(875,981)	(282,043)
Total deferred tax expense	711,954	(197,412)
Income tax expense	$ 12,157,487	$ 4,440,508

The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate to the income tax provision in our financial statements. Our effective tax rate for 2022 differs from the statutory rate primarily due to states taxes and the recognition of a valuation allowance on our Canadian and Oklahoma state deferred tax assets. Our effective tax rate for 2021 differs from the statutory rate primarily due to states taxes and the recognition of a valuation allowance on our Canadian and Oklahoma state deferred tax assets.

	Year Ended December 31, 2022	Effective Tax Rate	Year Ended December 31, 2021	Effective Tax Rate
Income tax provision computed at the statutory federal tax rate	$ 9,977,555	21.00 %	$ 3,377,625	21.00 %
Difference in Canadian and U.S. tax rate	(14,005)	(0.03)%	(11,433)	(0.07)%
Adjustment of Canadian deferred tax balances	39,839	0.08 %	762,000	4.74 %
Valuation allowance on Canadian loss	121,220	0.26 %	(688,388)	(4.28)%
Return to provision adjustment	(4,538)	(0.01)%	57,875	0.36 %
State taxes	2,304,218	4.85 %	1,057,924	6.58 %
State valuation allowance	(107,030)	(0.23)%	(107,545)	(0.67)%
Miscellaneous other items	(159,772)	(0.34)%	(7,550)	(0.05)%
Income tax expense	**$ 12,157,487**	**25.58 %**	**$ 4,440,508**	**27.61 %**

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.

Net deferred tax liabilities consisted of the following at December 31, 2022 and 2021:

	As of December 31, 2022	As of December 31, 2021
Deferred tax assets:		
State net operating loss carryforwards	$ 313,018	$ 244,582
Canadian net operating loss carryforwards	11,113,319	11,669,601
ARO	702,522	796,339
Unrealized derivatives/other	92,785	255,852
Gross deferred tax assets	12,221,644	12,966,374
Valuation allowance	(11,158,602)	(11,821,914)
Total deferred tax assets	1,063,042	1,144,460
Deferred tax liabilities:		
Oil and gas property	(9,336,638)	(8,558,064)
Partnership	(2,034,995)	(2,491,836)
Unrealized derivatives/other	(308,803)	—
Gross deferred tax liabilities	(11,680,436)	(11,049,900)
Net deferred tax liability	**$ (10,617,394)**	**$ (9,905,440)**

As of December 31, 2022, we have no U.S. federal net operating loss carry-forwards and approximately $9.9 million of state net operating loss carry-forwards, of which $0.3 million expires in 2037 and the remaining can be carried forward indefinitely. These loss carryforwards may reduce future taxable income, however, the extent of which may be limited due to any Internal Revenue Code Section 382 limitation. A state valuation allowance of $0.05 million is applicable to the net state deferred tax assets attributable to Oklahoma because of objective negative evidence on the cumulative loss incurred in the state over the three-year period ended December 31, 2022. As of December 31, 2022, we have $40.6 million of Canadian net operating loss carry-forwards. A separate valuation allowance of $11.1 million attributable to Canadian net operating losses and other tax carryovers is recorded because it is more likely than not to be utilized.

On August 16, 2022, legislation commonly known as the Inflation Reduction Act was signed into law. Among other things, the Inflation Reduction Act includes a 1% excise tax on corporate stock repurchases applicable to repurchases after December 31, 2022, and also a new minimum tax based on book income. While we do not currently expect the Inflation Reduction Act to have a material impact on our effective tax rate in 2022, our analysis of the impact of the Inflation Reduction Act on us is ongoing, and it is possible that the Inflation Reduction Act (or implementing regulations and other guidance, which have not yet been issued) could adversely impact our current and deferred federal tax liability in future periods.

The Company does not have any material uncertain tax positions. The Company recognizes interest expense and penalties related to the uncertain tax position in the income tax expense line in the accompanying consolidated statements of operations and comprehensive loss. Accrued interest and penalties are included in other non-current liabilities in the consolidated balance sheets and were $0 as of December 31, 2022 and 2021.

10. Commitments and Contingencies

Leases

As a result of the adoption of Leases (Topic 842), the Company recognized an operating lease as of December 31, 2022 summarized in the following table (in thousands):

	Amount
Asset	
Operating lease right-of-use assets	$ 31,383
Total operating lease right-of-use assets	$ 31,383
Liabilities	
Operating lease liabilities	$ 35,299
Total operating lease liabilities	$ 35,299
Operating lease costs	$ 32,097
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 106,798
Weighted average remaining lease term - operating lease	0.33
Weighted average discount rate (annualized) - operating lease	8.09%

Rent expense for operating leases for the year ended December 31, 2021 was $0.18 million as presented in other general and administrative expenses in the consolidated statements of operations and comprehensive income.

The following is a maturity analysis of the annual undiscounted cash flows of the operating lease liability as of December 31, 2022:

Amounts due in the year ended December 31,	Operating Leases
2023	$ 36,013
Total minimum lease payments	36,013
Less: effect of discounting	714
Present value of future minimum lease payments	35,299
Less: current obligations under leases	35,299
Long-term lease obligations	$ —

The Company's future minimum lease commitments as of December 31, 2021 are summarized in the following table:

Year ended December 31,	Payments
2022	$ 106,797
2023	36,013
	$ 142,810

The expiration date of the current lease is April 2023 and the Company has chosen not to extend that lease. As of December 31, 2022, the Company entered into a new office lease that commenced on March 1, 2023. The lease is for 70 months with future lease payments estimated to be approximately $0.85 million. There are no other pending leases, and no lease arrangements in which the Company is the lessor.

Other commitments

The Company also enters into commitments for capital expenditures in advance of the expenditures being made. As of December 31, 2022, we had commitments of $0.8 million for capital expenditures.

Litigation

On March 10, 2021, Epsilon filed a complaint against Chesapeake Appalachia, LLC ("Chesapeake") in the United States District Court for the Middle District of Pennsylvania, Scranton, Pennsylvania ("Middle District"). Epsilon claims that Chesapeake has breached a settlement agreement and several operating agreements ("JOAs") to which Epsilon and Chesapeake are parties. Epsilon asserts that Chesapeake has failed to cooperate with Epsilon's efforts to develop resources in the Auburn Development, located in Northeast Pennsylvania, as required under both the settlement agreement and JOAs.

Epsilon requested a preliminary injunction but was unsuccessful in obtaining that injunction. Epsilon filed a motion to amend its original Complaint. Chesapeake opposed. The Court ruled in Epsilon's favor and allowed Epsilon's amendment. Chesapeake moved to dismiss the amended Complaint. The Court granted the motion to dismiss without prejudice to Epsilon's right to file a new lawsuit based on new proposals made after the Court's decision. Epsilon filed a motion for reconsideration of that decision, but the court denied the motion for reconsideration on January 18, 2022.

Epsilon filed a notice of appeal on February 15, 2022 challenging both the motion to dismiss and motion for reconsideration decisions. Chesapeake filed a cross-appeal on March 1, 2022. A briefing schedule was set and briefing closed October 14, 2022. Oral argument was held in January 2023. A decision on the appeal is not expected until mid-2023.

Epsilon re-filed a complaint against Chesapeake in the Middle District on May 9, 2022. Epsilon generally asserts similar claims as in the previous suit, pursuing declaratory judgment claims regarding Chesapeake's obligation to Epsilon to cooperate with Epsilon's efforts in the Auburn Development and regarding Chesapeake's obstruction of Epsilon's efforts with the Pennsylvania Department of Environmental Protection permitting process but not based on specific well proposals. Chesapeake filed a motion to stay pending a decision on the Third Circuit appeal, which was granted. The matter is stayed pending a decision from the Third Circuit.

11. Net Income Per Share

Basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the period. Diluted net income per share is computed based upon the weighted-average number of common shares outstanding during the period plus the assumed issuance of common shares for all potentially dilutive securities.

The net income used in the calculation of basic and diluted net income per share are as follows:

	Year ended December 31,	
	2022	2021
Net income available to shareholders	$ 35,354,679	$ 11,627,517

In calculating the net income per share, basic and diluted, the following weighted-average shares were used:

	Year ended December 31, 2022	Year ended December 31, 2021
Basic weighted-average number of shares outstanding	23,319,633	23,705,193
Dilutive stock options	15,831	—
Unvested time-based restricted shares	—	82,958
Unvested performance-based restricted shares	70,725	68,951
Diluted weighted average shares outstanding	23,406,189	23,857,102

We excluded the following shares from the diluted EPS because their inclusion would have been anti-dilutive.

	Year ended December 31, 2022	Year ended December 31, 2021
Anti-dilutive options	54,169	218,750
Anti-dilutive unvested time-based restricted shares	273,448	83,044
Anti-dilutive unvested performance-based restricted shares	28,519	82,549
Total Anti-dilutive shares	356,136	384,343

12. Operating Segments

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision-maker. The chief operating decision-maker, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as executive management. Segment performance is evaluated based on operating profit or loss as shown in the table below. Interest expense, interest income and income taxes are managed separately on a group basis.

The Company’s reportable segments are as follows:

a. The Upstream segment activities include acquisition, development and production of primarily natural gas reserves on properties within the United States;
b. The Gas Gathering segment partners with two other companies to operate a natural gas gathering system; and
c. The Corporate segment activities include corporate listing and governance functions of the Company.

Segment activity as of, and for the years ended December 31, 2022 and 2021 is as follows:

	Upstream	Gas Gathering	Corporate	Elimination	Consolidated
As of and for the year ended December 31, 2022					
Operating revenue					
Natural gas	$ 56,948,734	$ —	$ —	$ —	$ 56,948,734
Natural gas liquids	1,733,130	—	—	—	1,733,130
Oil and condensate	3,195,333	—	—	—	3,195,333
Gathering and compression fees	—	9,609,172	—	(1,523,660)	8,085,512
Total operating revenue [1]	61,877,197	9,609,172	—	(1,523,660)	69,962,709
Operating costs					
Operating costs	15,079,783	2,287,763	706,849	(1,523,660)	16,550,735
Depletion, depreciation, amortization and accretion	5,375,225	1,063,286	—	—	6,438,511
Operating income	41,422,189	6,258,123	(706,849)	—	46,973,463
Other income (expense)					
Interest income	447,128	—	5,749	—	452,877
Interest expense	(50,782)	—	—	—	(50,782)
Gain (loss) on derivative contracts	236,077	—	—	—	236,077
Other (expense) income	(100,315)	—	846	—	(99,469)
Other income (expense), net	532,108	—	6,595	—	538,703
Net income before income tax expense	$ 41,954,297	6,258,123	(700,254)	—	47,512,166
Segment assets	$ 112,450,893	10,603,000	808,350	—	123,862,243
Capital expenditures [2]	6,785,930	163,914	—	—	6,949,844
Proved properties	40,596,972	—	—	—	40,596,972
Unproved properties	18,169,157	—	—	—	18,169,157
Gathering system	—	8,138,261	—	—	8,138,261
Operating lease right-of-use asset	31,383	—	—	—	31,383
Other property and equipment	923,799	—	—	—	923,799
As of and for the year ended December 31, 2021					
Operating revenue					
Natural gas	$ 31,708,185	—	—	—	31,708,185
Natural gas liquids	1,053,486	—	—	—	1,053,486
Oil and condensate	1,776,496	—	—	—	1,776,496
Gathering and compression fees	—	9,460,508	—	(1,594,683)	7,865,825
Total operating revenue [1]	34,538,167	9,460,508	—	(1,594,683)	42,403,992
Operating costs					
Operating costs	13,867,817	2,321,329	570,192	(1,594,683)	15,164,655
Depletion, depreciation, amortization and accretion	5,278,617	1,348,399	—	—	6,627,016
Operating income	15,391,733	5,790,780	(570,192)	—	20,612,321
Other income (expense)					
Interest income	38,865	—	—	—	38,865
Interest expense	(101,382)	—	—	—	(101,382)
Gain (loss) on derivative contracts	(4,482,909)	—	—	—	(4,482,909)
Other (expense) income	2,585	—	(1,455)	—	1,130
Other income (expense), net	(4,542,841)	—	(1,455)	—	(4,544,296)
Net income before income tax expense	$ 10,848,892	5,790,780	(571,647)	—	16,068,025
Segment assets	$ 85,828,508	13,506,775	127,311	—	99,462,594
Capital expenditures [2]	4,638,448	272,442	—	—	4,910,890
Proved properties	35,551,441	—	—	—	35,551,441
Unproved properties	21,700,926	—	—	—	21,700,926
Gathering system	—	9,031,137	—	—	9,031,137
Other property and equipment	946,866	—	—	—	946,866

(1) Segment operating revenue represents revenues generated from the operations of the segment. Inter-segment sales during the years ended December 31, 2022 and 2021 have been eliminated upon consolidation. For the year ended December 31, 2022, we sold natural gas to 26 unique customers. Direct Energy Business Marketing, LLC and EQT Energy, LLC each accounted for 10% or more of our total revenue. For the year

ended December 31, 2021, we sold natural gas to 30 unique customers. Direct Energy Business Marketing, LLC and SWN Energy Services Company, LLC each accounted for 10% or more of our total revenue.

(2) Capital expenditures for Upstream consist primarily of the drilling and completing of wells while Gas Gathering consists of expenditures relating to the installation of additional gathering facilities.

13. Commodity Risk Management Activities

Commodity Price Risks

Epsilon engages in price risk management activities from time to time. These activities are intended to manage Epsilon's exposure to fluctuations in commodity prices for natural gas by securing fixed price contracts for a portion of expected sales volumes.

Inherent in the Company's fixed price contracts, are certain business risks, including market risk and credit risk. Market risk is the risk that the price of oil and natural gas will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the Company's counterparty to a contract. The Company does not currently require collateral from any of its counterparties nor does its counterparties require collateral from the Company.

The Company enters into certain commodity derivative instruments to mitigate commodity price risk associated with a portion of its future natural gas production and related cash flows. The natural gas revenues and cash flows are affected by changes in commodity product prices, which are volatile and cannot be accurately predicted. The objective for holding these commodity derivatives is to protect the operating revenues and cash flows related to a portion of the future natural gas sales from the risk of significant declines in commodity prices, which helps ensure the Company's ability to fund the capital budget.

Epsilon has historically elected not to designate any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounts for these financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as g*ain (loss) on derivative contracts* on the consolidated statements of operations and comprehensive income. The related cash flow impact is reflected in cash flows from operating activities. During 2022, Epsilon recognized gains on financial commodity derivative contracts of $236,077. This amount included settlements of these contracts of $1,225,837. For 2021, Epsilon recognized losses on financial commodity derivative contracts of $4,482,909. This amount included settlements of these contracts of $4,243,085.

Commodity Derivative Contracts

At December 31, 2022, the Company had outstanding NYMEX HH swaps totaling 1.07 Bcf and Tennessee Z4 basis swaps totaling 1.07 Bcf outstanding. At December 31, 2021, Epsilon had two natural gas commodity two-way costless collar contracts totaling 0.59 Bcf outstanding.

	Fair Value of Derivative Assets	
	December 31, 2022	**December 31, 2021**
Current		
NYMEX Henry Hub swap	$ 1,219,865	$ —
Tennessee Z4 basis swap	181,775	—
Two-way costless collar	—	13,312
	$ 1,401,640	$ 13,312

	Fair Value of Derivative Liabilities	
	December 31, 2022	December 31, 2021
Current		
Tennessee Z4 basis swap	$ (179,550)	$ —
Two-way costless collar	—	(253,136)
	$ (179,550)	$ (253,136)
Net Fair Value of Derivatives	$ 1,222,090	$ (239,824)

The following table presents the changes in the fair value of Epsilon's commodity derivatives for the periods indicated:

	Year ended December 31,	
	2022	2021
Fair value of asset (liability), beginning of the period	$ (239,824)	$ —
Gains (losses) on derivative contracts included in earnings	236,077	(4,482,909)
Settlement of commodity derivative contracts	1,225,837	4,243,085
Fair value of asset (liability), end of the period	$ 1,222,090	$ (239,824)

14. Asset Retirement Obligations

Asset retirement obligations are estimated by management based on Epsilon's net ownership interest in all wells and the gathering system, estimated costs to reclaim and abandon such assets and the estimated timing of the costs to be incurred in future periods, and the forecast risk free cost of capital. Epsilon has estimated the net present value of its total asset retirement obligations to be $2.8 million as of December 31, 2022 ($2.8 million at December 31, 2021) based on a total net future undiscounted liability of approximately $7.4 million ($7.4 million at December 31, 2021). Each year we review, and to the extent necessary, revise our asset retirement obligations estimates.

The following table presents the activity in Epsilon's asset retirement obligations for the periods indicated:

	Year Ended December 31, 2022	Year ended December 31, 2021
Balance beginning of period	$ 2,833,656	$ 3,150,243
Liabilities acquired	12,053	7,009
Liabilities disposed of	(25,835)	(381,346)
Wells plugged and abandoned	(118,260)	(31,945)
Change in estimates	—	(8,299)
Accretion	78,623	97,994
Balance end of period	$ 2,780,237	$ 2,833,656

NATURAL GAS AND OIL PRODUCING ACTIVITIES

Natural gas and oil Reserves

Users of this information should be aware that the process of estimating quantities of ‘‘proved,’’ ‘‘proved developed’’ and ‘‘proved undeveloped’’ crude oil, natural gas liquids (NGLs) and natural gas reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity; evolving production history; crude oil and condensate, NGL and natural gas prices; and continual reassessment of the viability of production under varying economic conditions.

Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of crude oil, NGLs and natural 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 under then-existing economic conditions, operating methods and government regulations before 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.

Proved developed reserves are proved reserves expected to be recovered under operating methods being utilized at the time the estimates were made, through wells and equipment in place or if the cost of any required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those 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. PUDs can be recorded in respect of a particular undrilled location only if the location is scheduled, under the then-current drilling and development plan, to be drilled within five years from the date that the PUDs are to be recorded, unless specific factors (such as those described in interpretative guidance issued by the Staff of the SEC) justify a longer timeframe. Likewise, absent any such specific factors, PUDs associated with a particular undeveloped drilling location shall be removed from the estimates of proved reserves if the location is scheduled, under the then-current drilling and development plan, to be drilled on a date that is beyond five years from the date that the PUDs were recorded. Epsilon has formulated development plans for all drilling locations associated with its PUDs at December 31, 2022. Under these plans, each PUD location will be drilled within five years from the date it was recorded.

Estimates for PUDs are not attributed 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.

The following tables set forth Epsilon’s net proved reserves at December 31, 2022 and 2021 and changes for each of the two years in the year ended December 31, 2022. Net proved reserves at December 31 are estimated by the Company’s independent petroleum engineers, DeGolyer and MacNaughton.

EPSILON ENERGY LTD.
Supplemental Information to Consolidated Financial Statements
(Unaudited)

NET PROVED RESERVE SUMMARY

All reserves located in United States	Pennsylvania Natural Gas (MMcf)	Oklahoma Natural Gas (MMcf)	Oklahoma NGL (MBbl)	Oklahoma Oil (MBbl)	Total (MMcfe)
Net proved developed reserves at December 31, 2020	63,469	320	-	19	63,903
Revisions of previous estimates [1][2]	15,950	903	186	(10)	17,909
Divestitures	-	(60)	-	(1)	(66)
Transfers from proved undeveloped	513	1,364	-	83	2,375
Production	(9,830)	(403)	(29)	(25)	(10,557)
Net proved developed reserves at December 31, 2021	70,102	2,124	157	66	73,564
Revisions of previous estimates [3][4]	10,837	(665)	(65)	12	9,856
Divestitures	-	-	-	-	-
Transfers from proved undeveloped	4,389	1,682	150	61	7,334
Production	(9,026)	(477)	(44)	(32)	(9,959)
Net proved developed reserves at December 31, 2022	76,302	2,664	198	107	80,795
Net proved undeveloped reserves at December 31, 2020	15,915	8,954	299	353	28,781
Revisions of previous estimates [5][6]	11,532	(1,099)	281	(67)	11,717
Extensions and discoveries [7][8]	4,388	930	83	36	6,032
Transfers from proved undeveloped	(513)	(1,364)	-	(83)	(2,375)
Net proved undeveloped reserves at December 31, 2021	31,322	7,421	663	239	44,155
Revisions of previous estimates [9][10]	(18,738)	(2,860)	(220)	(74)	(23,362)
Extensions and discoveries	-	-	-	-	-
Transfers from proved undeveloped	(4,389)	(1,682)	(150)	(61)	(7,334)
Net proved undeveloped reserves at December 31, 2022	8,195	2,879	293	104	13,459
Net proved reserves at December 31, 2020	79,384	9,274	299	372	92,684
Revisions of previous estimates	27,482	(196)	467	(77)	29,626
Extensions and discoveries	4,388	930	83	36	6,032
Divestitures	-	(60)	-	(1)	(66)
Production	(9,830)	(403)	(29)	(25)	(10,557)
Net proved reserves at December 31, 2021	101,424	9,545	820	305	117,719
Revisions of previous estimates	(7,901)	(3,525)	(285)	(62)	(13,506)
Extensions and discoveries	-	-	-	-	-
Divestitures	-	-	-	-	-
Production	(9,026)	(477)	(44)	(32)	(9,959)
Net proved reserves at December 31, 2022	84,497	5,543	491	211	94,254
Proved developed reserves:					
At December 31, 2020	63,469	320	-	19	63,903
At December 31, 2021	70,102	2,124	157	66	73,564
At December 31, 2022	76,302	2,664	198	107	80,795
Proved undeveloped reserves:					
At December 31, 2020	15,915	8,954	299	353	28,781
At December 31, 2021	31,322	7,421	663	239	44,155
At December 31, 2022	8,195	2,879	293	104	13,459

(1) Revisions of previous estimates for Pennsylvania for 2021 include additions of 11,202 Mmcfe related to well performance and 4,748 Mmcfe related to commodity pricing.

(2) Revisions of previous estimates for Oklahoma for 2021 include additions of 2,160 Mmcfe related to well performance, 423 Mmcfe related to commodity pricing, and reduction of 624 Mmcfe related to property interest adjustments.

(3) Revisions of previous estimates for Pennsylvania for 2022 include additions of 6,261 Mmcfe related to well performance and 4,576 Mmcfe related to commodity pricing.

(4) Revisions of previous estimates for Oklahoma for 2022 include additions of 267 Mmcfe related to commodity pricing, 253 Mmcfe related to changes in previously adopted development plans, and reduction of 1,505 Mmcfe related to well performance.

(5) Revisions of previous estimates for Pennsylvania for 2021 include additions of 11,572 Mmcfe related to changes to the previously adopted development plan, 566 Mmcfe related to commodity pricing, and reductions of 606 Mmcfe related to well performance.

(6) Revisions of previous estimates for Oklahoma for 2021 include additions of 246 Mmcfe related to commodity pricing, 205 Mmcfe related to well performance, 107 Mmcfe related to property interest adjustments, and reduction of 373 Mmcfe from changes to the previously adopted development plan.

(7) Extensions and discoveries for Pennsylvania for 2021 include additions of 4,388 Mmcfe related to the proposal and development by the operator of a well that was not previously included in the development schedule.

(8) Extension and discoveries for Oklahoma for 2021 include additions of 865 Mmcfe related to recent offset development, and 779 Mmcfe related to exercising the Company’s option to participate in two new wells that were not previously included in the development schedule.

(9) Revisions of previous estimates for Pennsylvania for 2022 include reductions of 18,898 Mmcfe related to changes to the previously adopted development plan, reductions of 25 Mmcfe related to well performance, and additions of 185 Mmcfe related to commodity pricing.

(10) Revisions of previous estimates for Oklahoma for 2022 include additions of 41 Mmcfe related to commodity pricing, reductions of 58 Mmcfe related to well performance, and reduction of 4,607 Mmcfe from changes to the previously adopted development plan.

Capitalized Costs Relating to Natural gas and oil Producing Activities

The following table sets forth the capitalized costs relating to Epsilon’s crude oil and natural gas production and gathering activities at December 31, 2022 and 2021:

	Year ended December 31,	
	2022	**2021**
Proved properties	$ 148,326,265	$ 138,032,413
Unproved properties	18,169,157	21,700,926
Gathering system properties	42,639,001	42,475,086
Total Oil & Gas Properties	209,134,423	202,208,425
Accumulated depreciation, depletion, amortization and impairment	(142,230,033)	(135,924,921)
Net capitalized costs	$ 66,904,390	$ 66,283,504

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

	Year ended December 31,	
	2022	**2021**
Oil and Natural Gas Activities:		
Unproved acquisition costs	$ 310,211	$ 148,863
Development costs	6,426,037	3,751,827
Total costs incurred for oil and natural gas activities	6,736,248	3,900,690
Gathering System development costs	163,915	272,442
Total costs incurred	$ 6,900,163	$ 4,173,132

Results of Operations for Natural Gas and Oil Producing Activities

The following table sets forth results of operations for natural gas and oil producing activities for the years ended December 31, 2022 and 2021:

	Year ended December 31,	
	2022	**2021**
Oil and gas producing activities:		
Gas sales	$ 56,948,734	$ 31,708,185
Oil and other liquid sales	4,928,463	2,829,982
Total revenues	61,877,197	34,538,167
Lease operating costs	(7,128,631)	(7,897,738)
Depreciation, depletion, amortization, accretion and impairment	(5,375,225)	(5,431,675)
Total costs	(12,503,856)	(13,329,413)
Results of operations from oil and gas producing activities	$ 49,373,341	$ 21,208,754

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural gas and oil Reserves

The following information has been developed utilizing procedures prescribed by the Extractive Industries—Natural Oil and Gas Topic 932 of the ASC and based on natural gas reserves and production volumes estimated by our independent petroleum consultants, DeGolyer and MacNaughton. The commodity prices estimated below were based on a 12-month average of first-day-of-the-month commodity prices for the years 2022 and 2021. The following information may be useful for certain comparative purposes, but should not be solely relied upon in evaluating Epsilon or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of Epsilon.

The future cash flows presented below are based on expense and cost rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards. The resulting tax-effected future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable and possible reserves as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of Epsilon's gas reserves as of December 31, 2022 and 2021.

	Year ended December 31,	
	2022	**2021**
Future cash inflows	$ 529,886,325	$ 353,162,054
Future production costs	(119,404,233)	(104,161,488)
Future development costs(1)	(21,171,395)	(36,751,965)
Future income taxes(2)	(97,165,344)	(60,131,474)
10% annual discount for estimated timing of cash flows	(146,368,246)	(74,408,997)
Standardized measure of discounted future net cash flows	$ 145,777,107	$ 77,708,130

(1) Costs associated with the abandonment of proved properties are included in future development costs.

(2) Future income taxes for 2022 and 2021 were estimated using a combined federal and state statutory tax rate of approximately 26%.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2022 and 2021:

	Year ended December 31,	
	2022	**2021**
Beginning balance	$ 77,708,130	$ 16,015,868
Revenue less production and other costs	(53,224,969)	(26,680,071)
Changes in price, net of production costs	147,777,736	70,063,892
Development costs incurred	10,396,380	4,581,988
Net changes in future development costs	5,054,884	(8,732,332)
Extensions and discoveries, less related costs	—	3,705,395
Revisions of previous quantity estimates	(31,515,746)	40,997,786
Accretion of discount	9,790,852	2,218,430
Net change in income taxes	(17,827,596)	(25,325,983)
Purchases of reserves in place	—	446,240
Timing differences and other technical revisions	(2,382,564)	416,917
Ending balance	$ 145,777,107	$ 77,708,130

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and our principal financial officer, evaluated, as of the end of the period covered by this Annual Report on Form 10-K, the design and effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on that evaluation, our principal executive officer and principal financial officer have concluded that as of December 31, 2022, our disclosure controls and procedures were effective at the reasonable assurance level. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and our management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for Epsilon as such term is defined in the Exchange Act. Our internal control structure is designed to provide reasonable assurance that assets are safeguarded and that transactions are properly executed and recorded. The internal control structure includes, among other things, established policies and procedures, the selection and training of qualified personnel as well as management oversight.

With the participation of our management, we performed an evaluation of the effectiveness of our internal control over financial reporting based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "2013 Framework)". Based upon our evaluation under the 2013 Framework, we have concluded that as of December 31, 2022 our internal control over financial reporting was effective.

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by Epsilon's independent registered public accounting firm pursuant to rules of the SEC that permit Epsilon to provide only management's report in this Annual Report. We were not required to have, nor have we, engaged our independent registered public accounting firm to perform an audit of internal control over financial reporting pursuant to the rules of the Commission that permit us to provide only management's report in this Annual Report.

Changes in Internal Control Over Financial Reporting

There have been no significant changes in the Company's internal control over financial reporting during the quarter ended December 31, 2022 that have materially affected, or are 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.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The names, ages, business experience (for at least the past five years) and positions of our directors and executive officers as of December 31, 2022, are set out below. Our Board of Directors consisted of seven members at such date. All directors serve until the next annual meeting of shareholders or until their successors are elected or appointed and qualified. The Board of Directors appoints the executive officers annually.

Directors and Executive Officers	Age	Position with us
Jason Stabell	48	Chief Executive Officer and Director
Andrew Williamson	34	Chief Financial Officer
Henry N. Clanton	60	Chief Operating Officer
John Lovoi	62	Chairman of the Board and Director
Jacob Roorda	65	Director
Tracy Stephens	62	Director
Stephen Finlayson	68	Director
Jason Stankowski	52	Director
David Winn	60	Director

Biographies of Corporate Directors and Executive Officers.

Jason Stabell. Mr. Stabell has served as chief executive officer and a director for Epsilon Energy Ltd. since July 2022. He has worked in the energy industry since 1998 with a focus on upstream E&P. Most recently he served as President and CEO of Merlon International, LLC, a privately held company with assets in the Western Desert of Egypt and US Gulf Coast which was sold in 2019 to a publicly listed UK company where he served as an advisor until 2021. Previously, he served as CFO and ultimately President of privately held Merlon Petroleum Company, which had assets in the US Gulf Coast and Egypt and was sold in 2006. He has a BA in Economics from Williams College. We believe that Mr. Stabell is qualified to serve a s a member of our board of directors as a result of his experience in the natural gas and oil industry.

Andrew Williamson. Mr. Williamson has served as our chief financial officer since July 2022. He has spent his entire career in the energy business. From 2012 to early 2019, he served as Corporate Development Manager then Vice President Finance (CFO) of Merlon International, LLC. More recently, he served as the Corporate Strategy Manager for Petrosantander Inc. Mr. Williamson started his career in management consulting advising energy clients on transaction due diligence, growth strategy, and cost reduction. He has a BBA in Finance and a BA in Political Science from Southern Methodist University.

Henry N. Clanton. Mr. Clanton has served as our chief operating officer since January 2018. He has over 30 years of experience in the upstream E&P sector. His experience includes financial and technical management over all phases of drilling, completions, production, and field operations. Before joining us, he spent 14 years with a private E&P start-up, ARES Energy, Ltd, which he co-founded and served as a Managing Partner. Previous to that time Mr. Clanton worked with Schlumberger, ARCO Permian, and Coastal Management Company. He holds a MBA and a BS in Petroleum Engineering from Texas A&M University.

John Lovoi. Mr. Lovoi has been chairman of our board of directors since July 2013. Mr. Lovoi has been the managing partner of JVL Advisors, LLC, a private natural gas and oil investment advisor, since November 2002. He is a Director of Helix Energy Solutions Group, an operator of offshore natural gas and oil properties and production facilities, the Chairman of Dril-Quip, Inc., a provider of subsea, surface and offshore rig equipment. We believe that Mr. Lovoi is qualified to serve as a member of our board of directors as a result of his background in investment banking, equity research, and asset management, with an emphasis on the global natural gas and oil practice.

Jacob Roorda. Mr. Roorda has been a director of the Company since March 2016. He has also been a member of our Audit Committee since March 2016, and the chair of our Conflicts Committee since February 2018. Mr. Roorda has been a director of Lucero Energy Corp., a Bakken focused oil and natural gas producer, since 2012 and currently serves on the Reserves Committee of Lucero Energy Corp. Mr. Roorda was the President and CEO of Lucero Energy Corp. until February 2022. He was the Chief Executive Officer of Todd Energy Canada Ltd. from January 2015 to November 2016.

None of these positions are, or have ever been, with companies affiliated with the Company. He has been certified as a Professional Engineer by the Association of Professional Engineers and Geoscientists of Alberta since 1981. We believe that Mr. Roorda is qualified to serve as a member of our board of directors as a result of his experience in the natural gas and oil industry, including his natural gas and oil business development and engineering experience, and his financial industry experience.

Tracy Stephens. Mr. Stephens has been a director since May 2018. He has also been a member of our Compensation, Nominating and Corporate Governance Committee, and Conflicts Committee since February 2019. He is the founder of Westminster Advisors, a CEO advisory services company, and served as its Chief Executive Officer from January 2018. He was previously employed by Resources Global Professionals, a large business consulting company, from July 2001 to December 2016, and was the Chief Operating Officer the last three years. We believe that Mr. Stephens is qualified to serve as a member of our board of directors as a result of his extensive experience with public companies.

Stephen Finlayson. Mr. Finlayson has been a director since May 2019. He resigned from the audit committee and became a member of the Compensation, Nominating and Corporate Governance Committee in January 2021. In 2002, Mr. Finlayson founded and is currently Chairman of Applied Manufacturing Technologies (AMT), an independent international consulting and project services company. Prior to founding AMT, Mr. Finlayson headed Aspen Tech's professional services organization serving global customers in the hydrocarbon industries. Aspen Tech, a public company, trades under the symbol AZPN on the NASDAQ. Under Mr. Finlayson, Aspen's professional services organization delivered over 50% of company revenues. With his extensive experience in the hydrocarbon industries both in public and private companies we believe that Mr. Finlayson is qualified to serve as a member of our board of directors.

Jason Stankowski. Mr. Stankowski has been a director and member of the Audit Committee since January 2021. Mr. Stankowski is the founder and a partner and portfolio manager for Clayton Partners, LLC. He began his career at Prudential Securities in San Francisco and spent eight years in structured finance at CMA Capital Management, where he acted in a number of roles, including specializing in corporate retirement planning, structuring complex investment and financing structures for Fortune 1000 companies. He became designated as a Chartered Financial Analyst in 2003.

David Winn. Mr. Winn has been a director and member of the Audit Committee since January 2021. Mr. Winn recently retired from a 36 year career in public accounting that involved extensive board interaction. From 2003 until July 2020, Mr. Winn was an Audit Partner for Grant Thornton LLP, which is an independent audit, tax, and advisory firm and the U.S. member firm of Grant Thornton International Ltd. During his tenure, Mr. Winn served as audit department head, industry program leader, an engagement partner, quality control reviewer, and was a relationship partner to large clients. Mr. Winn has extensive Securities and Exchange Commission reporting experience with registration statements and annual and quarterly filings. Previously Mr. Winn served as a Director for PricewaterhouseCoopers LLP and previously as a Partner with Arthur Andersen LLP.

Corporate Governance Practices and Policies

Our corporate governance practices and policies are administered by the board of directors and by committees of the board appointed to oversee specific aspects of our management and operations, pursuant to written charters and policies adopted by the board and such committees.

The Board of Directors

The Board is committed to a high standard of corporate governance practices. The Board believes that this commitment is not only in the best interests of the shareholders but that it also promotes effective decision-making at the Board level. The Board is of the view that its approach to corporate governance is appropriate and complies with the objectives and guidelines relating to corporate governance set out in National Instrument 58-201 adopted by the Canadian securities administrators, or NI 58-201, as well as the governance requirements of the NASDAQ Global Market. In addition, the Board monitors and considers for implementation the corporate governance standards that are proposed by various Canadian regulatory authorities or that are published by various non-regulatory organizations in Canada. The Board has also established a Compensation Committee and Nominating and Corporate Governance Committee and has adopted a Compensation Committee Charter, and Nominating and Corporate Governance Charter to ensure the objectives of NI 58-201 and the NASDAQ Global Market are met.

Mr. Lovoi is the Managing Partner of JVL Advisors, LLC, beneficial owner of 7.79% of our common shares and Chairman of the Board.

The Board held nineteen meetings during 2022 and seven meetings during 2021. All Board meetings were conducted with open and candid discussions. As such, the independent directors did not hold any separate meetings, other than Audit and Compensation, Nominating and Corporate Governance Committee meetings that excluded directors who were not independent. The chairman of the Board is not an independent director. The independent members of the Board have the ability to meet on their own and are authorized to retain independent financial, legal and other experts as required whenever, in their opinion, matters come before the Board that require an independent analysis by the independent members of the Board. The Board intends to hold at least four regular meetings each year, as well as additional meetings as required. The Board has not established any required attendance levels for the Board and committee meetings. In setting the regular meeting schedule, care is taken to ensure that meeting dates are set to accommodate directors' schedules so as to encourage full attendance.

The Board has stewardship responsibilities, including responsibilities with respect to oversight of our investments, management of the Board, monitoring of our financial performance, financial reporting, financial risk management and oversight of policies and procedures, communications and reporting and compliance. In carrying out its mandate, the Board meets regularly and a broad range of matters are discussed and reviewed for approval. These matters include overall plans and strategies, budgets, internal controls and management information systems, risk management as well as interim and annual financial and operating results. The Board is also responsible for the approval of all major transactions, including property acquisitions, property divestitures, equity issuances and debt transactions, if any. The Board strives to ensure that our corporate actions correspond closely with the objectives of its shareholders. The Board will meet at least once annually to review in depth our strategic plan and review our available resources required to carry out our growth strategy and to achieve its objectives. The mandate of the Board is to be reviewed by the Board annually.

Position Descriptions. The Board has outlined the responsibilities in respect to our Chief Executive Officer, or CEO. The Board and CEO do not have a written position description for the CEO; however, the CEO's principal duties and responsibilities are planning our strategic direction, providing leadership, acting as our spokesperson, reporting to shareholders, and overseeing our executive management in particular with respect to operations and finance.

The charter for each of the Board committees outlines the duties and responsibilities of the members of each of the committees, including the chair of such committees. See ''Board Committees'' below.

Orientation and Continuing Education. We have not adopted a formalized process of orientation for new Board members. However, all directors have been provided with a base line of knowledge about us that serves as a basis for informed decision making. This includes a combination of written material, in person meetings with our senior management, site visits and other briefings and training, as appropriate.

Directors are kept informed as to matters affecting, or that may affect, our operations through reports and presentations at the quarterly Board meetings. Special presentations on specific business operations are also provided to the Board.

Ethical Business Conduct and Whistleblower Policy. Our Code of Ethics and Whistleblower Policy are available on our website at http://www.epsilonenergyltd.com/. Each director is expected to disclose all actual or potential conflicts of interest and refrain from voting on matters in which such director has a conflict of interest. In addition, a director must recuse himself from any discussion or decision on any matter of which the director is precluded from voting as a result of a conflict of interest. The Board has reviewed and approved a disclosure and insider trading policy for us, in order to promote consistent disclosure practices aimed at informative, timely and broadly disseminated disclosure of material information to the market in accordance with applicable securities legislation. The disclosure policy promotes, among other things, the disclosure and reporting of any serious weaknesses which may affect the financial stability and assets of us and our operating entities.

National Instrument 52-110 adopted by the Canadian securities administrators, the listing standards of the Toronto Stock Exchange and the listing standards of the NASDAQ Global Market require the Audit Committee to establish formal procedures for (a) the receipt, retention, and treatment of complaints received by us and our subsidiaries regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our consultants or employees of concerns regarding questionable accounting or auditing matters. We are committed to achieving compliance with all applicable securities laws and regulations, accounting standards, accounting controls and audit practices. In addition, we post on our website all disclosures that are required by law or the listing standards of the NASDAQ Global Market concerning any amendments to, or waivers from, any provision of the code.

Assessments. The Board does not conduct regular assessments of the Board, its committees or individual directors, however, the Board does periodically review and satisfy itself at meetings that the Board, its committees and its individual directors are performing effectively.

Board Diversity. Our Compensation, Nominating and Corporate Governance Committee is responsible for reviewing with the board of directors, on an annual basis, the appropriate characteristics, skills and experience required for the board of directors as a whole and its individual members. In evaluating the suitability of individual candidates (both new candidates and current members), the nominating and corporate governance committee, in recommending candidates for election, and the board of directors, in approving (and, in the case of vacancies, appointing) such candidates, will take into account many factors, including the following:

- personal and professional integrity, ethics and values;
- experience in corporate management, such as serving as an officer or former officer of a publicly held company;
- experience as a board member or executive officer of another publicly held company;
- strong finance experience;
- diversity of expertise and experience in substantive matters pertaining to our business relative to other board members;
- diversity of background and perspective, including, but not limited to, with respect to age, gender, race, place of residence and specialized experience;
- experience relevant to our business industry and with relevant social policy concerns; and
- relevant academic expertise or other proficiency in an area of our business operations.

Currently, our Board evaluates each individual in the context of the board of directors as a whole, with the objective of assembling a group that can best maximize the success of the business and represent stockholder interests through the exercise of sound judgment using its diversity of experience in these various areas.

Board Committees

The Board has three committees. The committees are the Audit Committee, the Compensation, Nominating and Corporate Governance Committee, and the Conflicts Committee. Each committee has been constituted with independent directors.

Audit Committee. The Audit Committee currently consists of David Winn (Chairman), Jacob Roorda, and Jason Stankowski. All members of the Audit Committee are independent and financially literate under the applicable rules and regulations of the SEC and the NASDAQ Global Market.

The Audit Committee meets at least on a quarterly basis to review and approve our consolidated financial statements before the financial statements are publicly filed.

The Audit Committee reviews our interim unaudited condensed consolidated financial statements and annual audited consolidated financial statements and certain corporate disclosure documents including the Annual Information Form, Management's Discussion and Analysis, and annual and interim earnings press releases before they are approved by the Board. The Audit Committee reviews and makes a recommendation to the Board in respect of the appointment and compensation of the external auditors and it monitors accounting, financial reporting, control and audit functions. The Audit Committee meets to discuss and review the audit plans of external auditors and is directly responsible for overseeing the work of the external auditors with respect to preparing or issuing the auditors' report or the performance of other audit, review or attest services, including the resolution of disagreements between management and the external auditors regarding financial reporting. The Audit Committee questions the external auditors independently of management and reviews a written statement of its independence. The Audit Committee must be satisfied that adequate procedures are in place for the review of our public disclosure of financial information extracted or derived from its consolidated financial statements and it periodically assesses the adequacy of those procedures. The Audit Committee must approve or pre-approve, as applicable, any non-audit services to be provided to us by the external auditors. In addition, it reviews and reports to the Board on our risk management policies and procedures and reviews the internal control procedures to determine their effectiveness and to ensure compliance with our policies and avoidance of conflicts of interest. The Audit Committee has established procedures for dealing with complaints or confidential submissions which come to its attention with respect to accounting, internal accounting controls or auditing matters. To date, neither the Board nor the Audit Committee has formally assessed any individual director with respect to their effectiveness and contribution to us in their capacity as a director. Instead, members of the Board have relied on informal conversations among themselves to adequately cover such matters.

The Audit Committee operates under a written charter that satisfies the applicable standards of the SEC and The NASDAQ Global Market. A copy of the Audit Committee Charter can be found on our website at www.epsilonenergyltd.com.

Compensation, Nominating and Corporate Governance Committee. The Compensation, Nominating and Corporate Governance Committee is currently comprised of Tracy Stephens (Chairman), John Lovoi, and Stephen Finlayson. Mr. Stephens and Mr. Finlayson are independent directors. Mr. Lovoi is not an independent director.

The Compensation, Nominating and Corporate Governance Committee's mandate is to:

1. Assist and advise the Board regarding its responsibility for oversight of our compensation policy; provided that all determinations on officer compensation will be subject to review and approval by the Board;
2. Study and evaluate appropriate compensation mechanisms and criteria;
3. Develop and establish appropriate compensation policies and practices for the Board and our senior management, including our security-based compensation arrangements;
4. Evaluate senior management;
5. Serve in an advisory capacity on organizational and personnel matters to the Board;
6. Assist the Board by identifying individuals qualified to serve on the Board and its committees;
7. Recommend to the Board the director nominees for the next annual meeting;
8. Recommend to the Board members and chairpersons for each committee;
9. Develop and recommend to the Board and review from time to time, a set of corporate governance principles and monitor compliance with such principles; and
10. Serve in an advisory capacity on matters of governance structure and the conduct of the Board.

These responsibilities include reporting and making recommendations to the Board for their consideration and approval. Corporate governance also relates to the activities of the Board, the members of which are elected by and are accountable to the shareholders, and takes into account the role of the individual members of management who are appointed by the Board and who are charged with the day-to-day management of us. The Board is committed to sound corporate governance practices, which are both in the interest of its shareholders and contribute to effective and efficient decision making.

The Compensation, Nominating and Corporate Governance Committee operates under a written charter that satisfies the applicable standards of the SEC and The NASDAQ Global Market. A copy of such charter can be found on our website at www.epsilonenergyltd.com.

Conflicts Committee. The Conflicts Committee currently consists of Jacob Roorda (Chairman), Tracy Stephens and Stephen Finlayson. All members are independent directors.

The Conflicts Committee has the power to advise the Board with respect to any matters or issues of concern to the Conflicts Committee in connection with any corporate opportunity and the interests of a related or conflicted party that the Conflicts Committee considers necessary or advisable.

Communications to the Board

Shareholders may communicate directly with our Board of Directors or any director by writing to the board or a director in care of the corporate secretary at Epsilon Energy Ltd., 500 Dallas Street, Suite 1250, Houston, Texas 77002, or by faxing their written communication to AeRayna Flores at (281) 668-0985. Shareholders may also communicate to the Board of Directors or any director by calling Ms. Flores at (281) 670-0002. Ms. Flores will review any communication before forwarding it to the board or director, as the case may be.

Employment Agreements

All named executive officers have executed employment contracts with us.

The Board appointed Jason Stabell to serve as CEO of the Company and as a member of the Board beginning on July 1, 2022 (the ("Stabell Effective Date"). In connection with Mr. Stabell's appointment, the Company entered into an Executive Employment Agreement with Mr. Stabell (the "Stabell Employment Agreement"), effective July 1, 2022. Pursuant to the Stabell Employment Agreement, the Company and Mr. Stabell have agreed that Mr. Stabell will serve as CEO on an "at-will" basis for an annual base salary of $300,000. In addition to his base salary, Mr. Stabell will be eligible to receive an annual incentive bonus targeted at $200,000 for achieving performance goals established by the Compensation Committee of the Board in its sole discretion for the then current calendar year. Additionally, Mr. Stabell will be eligible for equity awards in the form of Restricted Stock Units ("RSUs") with a grant date value of $600,000. The RSUs shall vest over a four-year period beginning on the Stabell Effective Date as follows: twenty-five percent (25%) of the RSUs on the first anniversary of the Stabell Effective Date, and an additional 6.25% of the RSUs vesting on the first day of each subsequent quarter, with full vesting on July 1, 2026, provided that Mr. Stabell is employed by the Company on each such vesting date. All outstanding RSUs shall vest at target upon a "Change in Control," as defined in the Equity Plan, provided Mr. Stabell then remains employed by the Company. Mr. Stabell will be entitled to participate in all applicable Company benefit plans, programs, or arrangements that the Company may offer to its executives generally, from time to time, and as may be amended from time to time. Participation will be subject to the terms of the applicable plan documents and generally applicable Company policies, as may be in effect from time to time, and any other restrictions or limitations imposed by law. If Mr. Stabell is terminated by the Company without cause or resigns for Good Reason (as defined in the Stabell Employment Agreement), he will be entitled to a severance payment equal to twenty-four (24) months' salary and the pro-rated target bonus for the year in which the termination takes place.

Mr. Henry Clanton's employment contract calls for a base pay of $250,000 per year.

The Board appointed Andrew Williamson to serve as CFO of the Company beginning on July 1, 2022 (the "Williamson Effective Date"). In connection with Mr. Williamson's appointment, the Company entered into an Executive Employment Agreement with Mr. Williamson (the "Williamson Employment Agreement"), effective July 1, 2022. Pursuant to the Williamson Employment Agreement, the Company and Mr. Williamson have agreed that Mr. Williamson will serve as CFO on an "at-will" basis for an annual base salary of $230,000. In addition to his base salary, Mr. Williamson will be eligible to receive an annual incentive bonus targeted at $150,000 for achieving performance goals established by the Compensation Committee of the Board in its sole discretion for the then current calendar year. Additionally, Mr. Williamson will be eligible for equity awards with a grant date value of $250,000. The RSUs shall vest over a four-year period beginning on the Williamson Effective Date as follows: twenty-five percent (25%) of the RSUs on the first anniversary of the Williamson Effective Date, and an additional 6.25% of the RSUs vesting on the first day of each subsequent quarter, with full vesting on July 1, 2026, provided that Mr. Williamson is employed by the Company on each such vesting date. All outstanding RSUs shall vest at target upon a "Change in Control," as defined in the Equity Plan, provided Mr. Williamson then remains employed by the Company. Mr. Williamson will be entitled to participate in all applicable Company benefit plans, programs, or arrangements that the Company may offer to its executives generally, from time to time, and as may be amended from time to time. Participation will be subject to the terms of the applicable plan documents and generally applicable Company policies, as may be in effect from time to time, and any other restrictions or limitations imposed by law. If Mr. Williamson is terminated by the Company without cause or resigns for Good Reason (as defined in the Williamson Employment Agreement), he will be entitled to a severance payment equal to twenty-four (24) months' salary and the pro-rated target bonus for the year in which the termination takes place.

ITEM 11. EXECUTIVE COMPENSATION.

Summary Compensation Table

Epsilon's board of directors (the "Board") adopted the 2020 Equity Incentive Plan (the "2020 Plan") on July 22, 2020 subject to approval by Epsilon's shareholders at Epsilon's 2020 Annual General and Special Meeting of shareholders, which occurred on September 1, 2020 (the "Meeting"). Shareholders approved the 2020 Plan at the Meeting. Following Epsilon's listing on the NASDAQ Global Market, the Board determined that it is in the best interest of the shareholders to approve a new incentive plan that is compliant with U.S. public company equity plan rules and practices that would replace Epsilon's Amended and Restated 2017 Stock Option Plan (including its predecessors) and the Share Compensation Plan (collectively referred to as the "Predecessor Plans"). No further awards will be granted under the Predecessor Plans.

The following table sets out information concerning the compensation paid to our principal executive officer and our two most highly compensated executive officers other than our principal executive officer, or our named executive officers for the two years ended December 31, 2022 and 2021. Compensation amounts in the following table are in U.S. dollars.

						Non-equity incentive plan compensation			
Name and principal position	Year	Salary	Bonuses	Share-based Awards	Option-based Awards	Annual Incentive Plans	Long-term Incentive Plans	Pension Value	Total Compensation
Jason Stabell, CEO (1)	2022	$ 150,000	$ 100,000	$ 600,000	$ —	$ —	$ —	$ —	$ 850,000
Henry N. Clanton, COO (2)	2022	$ 262,500	$ 117,000	$ 173,187	$ —	$ —	$ —	$ —	$ 552,687
	2021	$ 250,000	$ 75,000	$ —	$ —	$ —	$ —	$ —	$ 325,000
Andrew Williamson, CFO (3)	2022	$ 115,000	$ 75,000	$ 250,000	$ —	$ —	$ —	$ —	$ 440,000

(1) Mr. Stabell was hired as our chief executive officer in July 2022 with an annual base salary of US$300,000.

2022—Share award of 97,560 common shares under the 2020 Plan valued at $6.15 per share, market price on the grant date, July 1, 2022. The RSU's vest over a four-year period with 25% vesting on the first anniversary of Mr. Stabell's effective date and an additional 6.25% vesting on the first day of each subsequent quarter, with full vesting on July 1, 2026 so long as Mr. Stabell is still employed.

(2) Mr. Henry Clanton was hired as our chief operating officer in January 2018, His current base salary of US$262,500.

2022— Share award of 12,825 under the 2020 Plan valued at $6.33 per share, market price on the grant date, April 6, 2022, and a share award of 13,877 under the 2020 Plan valued at $6.63 per share, market price on the grant date, December 31, 2022, both of which vest evenly over a three year period, so long as Mr. Clanton is still employed.

(3) Mr. Andrew Williamson was hired as our chief financial officer in July 2022 with a base salary of US$230,000.

2022— Share award of 40,650 common shares under the 2020 Plan valued at $6.15 per share, market price on the grant date, July 1, 2022. The RSU's vest over a four-year period with 25% vesting on the first anniversary of Mr. Williamson's effective date and an additional 6.25% vesting on the first day of each subsequent quarter, with full vesting on July 1, 2026 so long as Mr. Williamson is still employed.

Description of the 2020 Equity Incentive Plan (the "2020 Plan")

The 2020 Plan was approved by the Board on July 22, 2020 and shareholders on September 1, 2020 as a replacement of our Amended and Restated 2017 Stock Option Plan and the Share Compensation Plan.

The 2020 Plan is administered by the Board, a committee of the Board or one or more officers delegated authority by the Board to administer the 2020 Plan. The Board has the authority in its discretion to interpret the 2020 Plan. The Board determines to whom stock options, stock appreciation rights, restricted stock and stock units, performance shares and units, other stock-based awards and cash-based awards are granted, subject to options and all other terms and conditions of the awards.

The maximum number common shares that may be issued under the 2020 Plan is 2,000,000. As of December 31, 2022, 234,834 performance stock units ("PSUs"), and 449,131 time-based restricted shares were outstanding, leaving 1,316,035 shares available to be granted under the 2020 Plan.

If the shares granted under the 2020 Plan expire or terminate for any reason without having been issued, they again become available for grant under the 2020 Plan. Shares granted under the 2020 Plan are not transferable or assignable other than by will or other testamentary instrument or the laws of succession.

In the event we undergo a change of control by a reorganization, acquisition, amalgamation or merger (or a plan or arrangement in connection with any of these) with respect to which all or substantially all of the persons who were the beneficial owners of the common shares immediately prior to such transaction do not, following such transaction, beneficially own, directly or indirectly more than 50% of the resulting voting power, a sale of all, or substantially all, of the Company's assets, or the liquidation, dissolution or winding-up of the Company, outstanding awards shall be subject to the definitive agreement entered into by the Company in connection with the change of control.

If an award holder resigns from the Company or is terminated by the Company (with or without cause), unvested shares will immediately be forfeited.

At December 31, 2022, we were authorized to issue equity securities as follows:

Plan Category	Number of Shares to be Issued Upon Exercise or Vesting of Outstanding Options or Shares	Weighted Average Exercise or Vesting Price of Outstanding Options or Shares	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity share options under Amended and Restated 2017 Stock Option Plan	70,000	$ 5.03	—
Common shares under 2020 Equity Incentive Plan	314,043	$ 5.89	1,316,035

Incentive Plan Awards for Named Executive Officers

Outstanding Share-Based Awards and Option-Based Awards as of December 31, 2022 are as follows:

	Option-based Awards				Share-based Awards		
Name	Number of Securities Underlying Unexercised Options	Option Exercise Price	Option Expiration Date	Value of Unexercised In-the-Money Options	Number of Shares or Units of Shares that Have Not Vested	Market or Payout Value of Share-Based Awards that Have Not Vested	Market or Payout Value of Vested Share-Based awards not Paid Out or Distributed
Jason Stabell	—	$		$ —	97,560	$ 646,823	$ —
Henry N. Clanton	30,000	$ 5.03	01/30/24	$ 48,000	23,334	$ 154,704	$ —
Andrew Williamson	—	$		$ —	40,650	$ 269,510	$ —

Incentive Plan Awards—Value Vested or Earned for Named Executive Officers

The values of incentive plan awards that were vested or earned during the year ended December 31, 2022 are as follows:

Name	Option-Based Awards—Value Vested During the Year	Share-based awards—Value Vested During the Year	Non-Equity Incentive Plan Compensation—Value Earned During the Year
Henry N. Clanton	$ —	$ 105,695	$ N/A

We have adopted the 2020 Plan as an incentive-based share award plan applicable to all named executive officers and employees.

Change of control is defined as any event whereby any person acquires at least 50% of The Company's stock or if a group of shareholders causes at least 50% of the board members to change.

DIRECTOR COMPENSATION

The following table contains compensation earned in the year ended December 31, 2022 by our independent directors who are not named executive officers:

Name	Fees Earned	Share-Based Awards	Option-Based	Non-Equity Incentive Plan Compensation	Pension Value	All Other Compensation	Total
John Lovoi*	$ —	$ 152,478	$ —	$ —	$ —	$ —	$ 152,478
Stephen Finlayson	$ 30,768	$ 41,778	$ —	$ —	$ —	$ —	$ 72,546
Jacob Roorda	$ 30,768	$ 41,778	$ —	$ —	$ —	$ —	$ 72,546
Tracy Stephens	$ 30,753	$ 41,778	$ —	$ —	$ —	$ —	$ 72,531
David Winn	$ 46,130	$ 41,778	$ —	$ —	$ —	$ —	$ 87,908
Jason Stankowski	$ 30,753	$ 41,778	$ —	$ —	$ —	$ —	$ 72,531

* Mr. Lovoi, who is not independent, only receives share-based awards for his service as a board member.

On a biannual basis, we compensate each director for services rendered (unless a director elects not to receive payment) and reimburse reasonable out-of-pocket travel expenses when incurred.

As of May 1, 2017, board member compensation is fixed at an annual fee of Cdn$80,000. Cdn$40,000 is paid in cash semi-annually in July and January and Cdn$40,000 paid as a share-based award.

Incentive Plan Awards—Value Vested or Earned During the Year for Directors (Other Than Named Executive Officers)

Outstanding Share-Based Awards and Option-Based Awards as of December 31, 2022 are as follows:

	Option-based Awards				Share-based Awards		
Name	Number of Securities Underlying Unexercised Options	Option Exercise Price	Option Expiration Date	Value of Unexercised In-the-Money Options	Number of Shares or Units of Shares that Have Not Vested	Market or Payout Value of Share-Based Awards that Have Not Vested	Market or Payout Value of Vested Share-Based awards not Paid Out or Distributed
John Lovoi	—	$ —		$ —	31,401	$ 208,189	$ 65,416
Stephen Finlayson	—	$ —		$ —	13,401	$ 88,849	$ 65,416
Jacob Roorda	12,500	$ 5.03	1/9/2024	$ 20,000	13,401	$ 88,849	$ 65,416
Tracy Stephens	—	$ —		$ —	13,401	$ 88,849	$ 65,416
David Winn	—	$ —		$ —	9,734	$ 64,536	$ 14,586
Jason Stankowski	—	$ —		$ —	9,734	$ 64,536	$ 14,586

The values of incentive plan awards that were vested or earned during the year ended December 31, 2022 are as follows:

Name	Option-Based Awards—Value Vested During the Year	Share-based awards—Value Vested During the Year	Non-Equity Incentive Plan Compensation—Value Earned During the Year
John Lovoi	$ —	$ 83,094	$ N/A
Stephen Finlayson	$ —	$ 83,094	$ N/A
Jacob Roorda	$ —	$ 83,094	$ N/A
Tracy Stephens	$ —	$ 83,094	$ N/A
David Winn	$ —	$ 32,262	$ N/A
Jason Stankowski	$ —	$ 32,262	$ N/A

Directors and Officers Liability Insurance

We maintain directors' and officers' liability insurance for the protection of our directors and officers against liability incurred by them in their capacities as our directors and officers. The policy provides an aggregate limit of liability of $30,000,000 with a deductible to us of $25,000 per loss. The annual premium for the Directors' and Officers' liability insurance is about $350,000 and is renewed annually. The premium is not allocated between Directors and Officers as separate groups.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The table set forth below is information with respect to beneficial ownership of common shares as of March 23, 2023, by our named executive officers, by each of our directors, by all our current executive officers and directors as a group, and by each person known to us who beneficially own 5% or more of the outstanding common shares. To our knowledge, each person named in the table has sole voting and investment power with respect to the common shares identified as beneficially owned.

Unless otherwise indicated, the address of each of the individuals named below is c/o Epsilon Energy Ltd., 500 Dallas, Suite 1250, Houston, Texas 77002.

Name of Beneficial Owner	Number of Common Shares	Percentage of Common Shares Owned
5% Stockholders		
Palo Duro Energy Fund, LP (1)	2,046,035	8.85 %
JVL Advisors, LLC (2)	1,759,588	7.61 %
Solas Capital Management LLC (3)	3,608,467	15.61 %
Named Executive Officers and Directors		
Jason Stabell (4)	36,000	*
Henry Clanton (5)	80,942	*
John Lovoi (6)	1,800,287	7.79 %
Stephen Finlayson (7)	24,199	*
Jacob Roorda (8)	113,599	*
Tracy Stephens (9)	45,099	*
David Winn (10)	12,366	*
Jason Stankowski (11)	314,726	*
All executive officers and directors as a group (8 persons) (12)	2,427,218	10.48 %

* Indicates beneficial ownership of less than 5% of outstanding shares.

(1) The address of Palo Duro Energy Fund, LP, or Palo Duro is 311 S. Wacker Drive, Suite 1250, Chicago, Illinois 60606. Matthew Dougherty is the managing partner of Palo Duro and exercises the voting and dispositive power with respect to the common shares held by Palo Duro.

(2) The address of JVL Advisors, LLC, or JVL, is 10000 Memorial Drive, Houston, Texas 77024. John Lovoi, the chairman of our board of directors, and the managing partner of JVL, exercises the voting and dispositive power with respect to the common shares held by JVL.

(3) The address of Solas Capital Management, LLC is 405 Park Avenue, New York, NY 10022. Pursuant to a Schedule 13G filed with the SEC on February 14, 2020, Solas Capital Management, LLC ("Solas") and Frederick Tucker Golden share voting and dispositive power with respect to these common shares. All of the securities reported are owned by advisory clients of Solas, none of which is a beneficial owner of more than 5% as of July 14, 2020.

(4) Mr. Stabell is our chief executive officer and a member of our board of directors.

(5) Includes 30,000 shares issuable upon the exercise (at exercise price of $5.03) of options exercisable within 60 days of March 25, 2021 (not yet expired). Mr. Clanton is our chief operating officer.

(6) Includes the shares held by JVL. Mr. Lovoi is the chairman of our board of directors.

(7) Mr. Finlayson is a member of our board of directors.

(8) Mr. Roorda is a member of our board of directors. Includes 25,000 shares held by Mr. Roorda’s spouse, and 12.500 shares issuable upon the exercise (at exercise price of $5.03) of options exercisable within 60 days of March 25, 2021 (not yet expired).

(9) Mr. Stephens is a member of our board of directors.

(10) Mr. Winn is a member of our board of directors.

(11) Mr. Stankowski is a member of our board of directors and a partner and portfolio manager for Clayton Partners, LLC.

(12) Includes 42,500 shares issuable upon the exercise (at exercise price of $5.03) of options exercisable within 60 days of March 25, 2021 (not yet expired).

Changes in Control. We do not know of any arrangement, the operation of which may at a subsequent date result in a change in control of us.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Certain Relationships and Related Transactions

Since the beginning of fiscal 2022, there has not been, nor is there currently proposed, any transaction or series of similar transactions to which we were or are a party in which the amount involved exceeded or exceeds $120,000 and in which any of our directors, executive officers, holders of more than 5% of any class of our voting securities, or any member of the immediate family of any of the foregoing persons, had or will have a direct or indirect material interest, except for the compensation and other arrangements described in “Executive Compensation” and “Director Compensation” elsewhere in this document and the transactions described below.

Independence of the Board of Directors

The Board is currently composed of seven directors who provide us with a wide diversity of business experience.

Our Board has determined that Messrs. Jacob Roorda, Tracy Stephens, Stephen Finlayson, Jason Stankowski and David Winn are independent in accordance with the listing requirements of the NASDAQ Global Market, representing over 50% of the Board. Our Board conducted its independence analysis for each of its current members other than John Lovoi and Michael Raleigh, considering all relevant facts and circumstances, including the director’s other commercial, accounting, legal, banking, consulting, charitable and familial relationships. Pursuant to its review, the Board determined that with respect to each of its current members other than John Lovoi and Michael Raleigh, there are no disqualifying factors with respect to director independence enumerated in the listing standards of NASDAQ or any relationships that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director, and that each such member is an “independent director” as defined in the listing standards of NASDAQ.

Indemnification of Officers and Directors

Under Section 124 of the Business Corporations Act (Alberta) (the "ABCA"), except in respect of an action by or on behalf of us or body corporate to procure a judgment in our favor, we may indemnify a current or former director or officer or a person who acts or acted at our request as a director or officer of a body corporate of which we are or were a shareholder or creditor and the heirs and legal representatives of any such persons (collectively, "Indemnified Persons") against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by any such Indemnified Person in respect of any civil, criminal or administrative actions or proceedings to which the director or officer is made a party by reason of being or having been our director or officer, if (i) the director or officer acted honestly and in good faith with a view to our best interests, and (ii) in the case of a criminal or administrative action or proceeding that is enforced by a monetary penalty, the director or officer had reasonable grounds for believing that such director's or officer's conduct was lawful (collectively, the "Indemnification Conditions").

Notwithstanding the foregoing, the ABCA provides that an Indemnified Person is entitled to indemnity from us in respect of all costs, charges and expenses reasonably incurred by the person in connection with the defense of any civil, criminal or administrative action or proceeding to which the person is made a party by reason of being or having been our director or officer, if the person seeking indemnity (i) was substantially successful on the merits in the person's defense of the action or proceeding, (ii) fulfills the Indemnification Conditions, and (iii) is fairly and reasonably entitled to indemnity. We may advance funds to an Indemnified Person for the costs, charges and expenses of a proceeding; however, the Indemnified Person shall repay the moneys if such individual does not fulfill the Indemnification Conditions. The indemnification may be made in connection with a derivative action only with court approval and only if the Indemnification Conditions are met.

As contemplated by Section 124(4) of the ABCA and our by-laws, we have acquired and maintain liability insurance for our directors and officers with coverage and terms that are customary for a company of our size in our industry of operations. The ABCA provides that we may not purchase insurance for the benefit of an Indemnified Person against a liability that relates to the person's failure to act honestly and in good faith with a view to our best interests.

Our by-laws provide that, subject to the ABCA, the Indemnified Persons shall be indemnified against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by such person in respect of any civil, criminal or administrative action or proceeding to which such person is made a party by reason of being or having been a director or officer of the Company or such body corporate, if the Indemnification Conditions are satisfied. In addition, pursuant to our by-laws, we may indemnify such person in such other circumstances as the ABCA or law permits.

Our by-laws also provide that none of our directors or officers shall be liable for the acts, receipts, neglects or defaults of any other director, officer or employee, or for joining in any receipt or other act for conformity, or for any loss, damage or expense happening to us through the insufficiency or deficiency of title to any property acquired for or on behalf of us, or for the insufficiency or deficiency of any security in or upon which any of our moneys shall be invested, or for any loss or damage arising from the bankruptcy, insolvency or tortious acts of any person with whom any of our moneys, securities or effects shall be deposited, or for any loss occasioned by any error of judgment or oversight on his part, or for any other loss, damage or misfortune which shall happen in the execution of the duties of his or her office or in relation thereto; provided that nothing in our by-laws shall relieve any director or officer from the duty to act in accordance with the ABCA and the regulations thereunder. The foregoing is premised on the requirement under our by-laws that each of our directors and officers in exercising his or her powers and discharging duties shall act honestly and in good faith with a view to our best interests and exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

We have entered into indemnification agreements with our directors and officers which generally require that we indemnify and hold the indemnitees harmless to the greatest extent permitted by law for liabilities arising out of the indemnitees' service to us and our subsidiaries as directors and officers, if the indemnitees acted honestly and in good faith with a view to our best interests and, with respect to criminal or administrative actions or proceedings that are enforced by monetary penalty, if the indemnitee had no reasonable grounds to believe that his or her conduct was unlawful. The indemnification agreements also provide for the advancement of defense expenses to the indemnitees by us.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The following table summarizes fees billed to us for fiscal 2022 and for fiscal 2021 by our principal auditors, BDO USA, LLP:

	December 31, 2022	December 31, 2021
Audit Fees:		
Audit of financial statements	$ 395,634	$ 407,588
Total Audit Fees	$ 395,634	$ 407,588

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a)1. Financial Statements:
Report of Independent Registered Public Accounting Firm (PCAOB ID 243)
Consolidated Balance Sheets as of December 31, 2022 and December 31, 2021.
Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2022 and December 31, 2021.
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2022 and December 31, 2021.
Consolidated Statements of Cash Flows for the years ended December 31, 2022 and December 31, 2021.
Notes to Consolidated Financial Statements

(a)2. Financial Statement Schedules:
There are no Financial Statement Schedules included with this filing for the reason that they are not required.

(a)3. Exhibits

3.1 Articles of Incorporation of Epsilon Energy Ltd (incorporated by reference to Exhibit 3.1 of Form 10, File No. 001-38770, filed on December 21, 2018).

3.2 Bylaws of Epsilon Energy Ltd. (incorporated by reference to Exhibit 3.2 of Form 10, File No. 001-38770, filed on December 21, 2018)

3.3 Articles of Amendment dated December 19, 2019 (incorporated by reference to Exhibit 3.3 of Form 10, File No. 001-38770, filed on December 21, 2018)

4.1 Description of Registrant's Securities Registered Under Section 12 of the Exchange Act. (incorporated by reference to Exhibit 4.1 of Form 10-K, File No. 001-38770, filed on March 18, 2020)

10.1 Credit Agreement, dated as of July 29, 2013, by and among Epsilon Energy USA Inc., the lenders from time to time party thereto, Texas Capital Bank, National Association ("TCB"), as the administrative agent, swing line lender and letter of credit issuer, and TCB as the sole lead arranger and sole book runner (incorporated by reference to Exhibit 10.1 of Form 10, File No. 001-38770, filed on December 21, 2018)

10.2 First Amendment to Credit Agreement, effective as of December 10, 2015 (incorporated by reference to Exhibit 10.2 of Form 10, File No. 001-38770, filed on December 21, 2018)

10.3 Second Amendment to Credit Agreement, effective as of October 11, 2016 (incorporated by reference to Exhibit 10.3 of Form 10, File No. 001-38770, filed on December 21, 2018)

10.4 Third Amendment to Credit Agreement, effective as of February 21, 2019 (incorporated by reference to Exhibit 10.4 of Form 10, File No. 001-38770, filed on December 21, 2018)

10.5 Fourth Amendment to Credit Agreement, effective as of August 4, 2019 (incorporated by reference to Exhibit 10.5 of Form 10, File No. 001-38770, filed on December 21, 2018)

10.6 Fifth Amendment to Credit Agreement, effective as of January 7, 2019 (incorporated by reference to Exhibit 10.6 of Form 10-K, File No. 001-38770, filed on March 29, 2019)

10.7* Sixth Amendment to Credit Agreement, effective as of January 7, 2019

10.8*	Seventh Amendment to Credit Agreement, effective as of January 7, 2019
10.9*	Eighth Amendment to Credit Agreement, effective as of January 7, 2019
10.10*	Ninth Amendment to Credit Agreement, effective as of January 7, 2019
10.11+	Henry Clanton Offer Letter (incorporated by reference to Exhibit 10.7 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.12	Anchor Shipper Gas Gathering Agreement, effective January 1, 2012, by and between Appalachia Midstream Services, L.L.C. and Epsilon Energy USA, Inc., as shipper and producer (incorporated by reference to Exhibit 10.8 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.13+	Amended and Restated 2017 Stock Option Plan (incorporated by reference to Exhibit 10.9 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.14+	Share Compensation Plan (incorporated by reference to Exhibit 10.10 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.15	Agreement for the Construction, Ownership, and Operation of Midstream Assets in AMI Area D of Northern Pennsylvania effective the 1st day of January, 2012, by and between Statoil Pipelines, LLC, a Delaware limited liability company formerly known as StatoilHydro Pipelines, LLC, Epsilon Midstream LLC, a Pennsylvania limited liability company, and Appalachia Midstream Services, L.L.C., an Oklahoma limited liability company (incorporated by reference to Exhibit 10.11 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.16+	Jason Stabell Executive Employment Agreement (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 001-38770, filed on June 24, 2022)
10.17+	Andrew Williamson Executive Employment Agreement (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 001-38770, filed on June 24, 2022)
21.1	Subsidiaries of the Registrant (incorporated by reference to Exhibit 21.1 of Form 10, File No. 001-38770, filed on December 21, 2018)
23.1*	Consent of DeGolyer and MacNaughton
23.2*	Consent of BDO USA, LLP
31.1*	Rule 13a-14(a)/15d-14(a) Certification.
31.2*	Rule 13a-14(a)/15d-14(a) Certification.
32.1**	Section 1350 Certifications.
32.2**	Section 1350 Certifications.
99.1*	Summary Reserve Report
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 (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith.

** Furnished herewith.

\+ Denotes a management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on March 23, 2023.

EPSILON ENERGY LTD.

By: /s/ *J. Andrew Williamson*
J. Andrew Williamson
Chief Financial Officer
(duly authorized to sign on behalf of the registrant)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	**Title**	**Date**
/s/ Jason Stabell Michael Raleigh	Chief Executive Officer and Director (Principal Executive Officer)	March 23, 2023
/s/ J. Andrew Williamson B. Lane Bond	Chief Financial Officer (Principal Financial and Accounting Officer)	March 23, 2023
/s/ John Lovoi John Lovoi	Chairman of the Board	March 23, 2023
/s/ Stephen Finlayson Stephen Finlayson	Director	March 23, 2023
/s/ Jacob Roorda Jacob Roorda	Director	March 23, 2023
/s/ Jason Stankowski Jason Stankowski	Director	March 23, 2023
/s/ Tracy Stephens Tracy Stephens	Director	March 23, 2023
/s/ David Winn David Winn	Director	March 23, 2023