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, 2019.

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.)

16945 Northchase Drive, Suite 1610
Houston, Texas 77060
(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

(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that 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 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: $43.7 million. There were 26,790,985 shares of Common Shares ($0 par value) outstanding as of March 18, 2020.

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 information'' 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, Inc. 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 New York Mercantile Exchange (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 our 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.

EXCHANGE RATE

The following tables set forth for the period indicated the rate used to convert one Canadian dollar to U.S. dollars, expressed in U.S. dollars. Within this report, all amounts are shown in US$ unless otherwise indicated.

	December 31, 2019	**December 31, 2018**
Daily Closing Rate	0.7715	0.7329
Average Rate	0.7536	0.7718
High Closing Rate	0.7715	0.8143
Low Closing Rate	0.7358	0.7326

ITEM 1. BUSINESS.

Summary

Epsilon Energy Ltd. (the "Company" or "Epsilon" or "we") was incorporated under the laws of the Province of Alberta, Canada 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. Our primary areas of operation are Pennsylvania and Oklahoma. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. 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, 2019, Epsilon's total estimated net proved reserves were 124,161 million cubic feet (MMcf) of natural gas reserves and 116,053 barrels (Bbl) of oil and other liquids. Epsilon held leasehold rights to approximately 78,101 gross (13,100 net) acres. The Company has natural gas production in the Marcellus 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, and Dewey Energy Holdings LLC, a Delaware limited liability company.

Substantially all of the production from our Pennsylvania acreage (4,130 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 2019, we paid $1.2 million to the Auburn GGS to gather and treat our 7.6 Bcf of natural gas production in Pennsylvania ($1.1 million to the Auburn GGS to gather and treat our 7.3 Bcf in 2018).

Our principal executive office is located at 16945 Northchase Drive, Suite 1610, Houston, Texas 77060, 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 2019

Operational Highlights

Marcellus Shale—Pennsylvania

- During the year ended December 31, 2019, Epsilon's realized natural gas price was $2.18 per Mcf, a 13% decrease over the year ended December 31, 2018.
- Total year ended December 31, 2019 natural gas production was 7.6 Bcf, as compared to 7.3 Bcf during 2018.
- Gathered and delivered 87.8 Bcf gross (30.7 Bcf net to Epsilon's interest) during the year, or 241 MMcf/d through the Auburn Gas Gathering System which represents approximately 73% of designed throughput capacity.
- We participated in the drilling and completion of 4 gross (1.07 net) lower Marcellus wells in 2019. These wells went into production in October. In addition, 5 wells (0.39 net) which were spud in Q4 2018 were completed and 4 were turned to production in February 2019, and the 5th was turned to production in June. Two of these wells targeted the Upper Marcellus.

Anadarko, NW Stack Trend—Oklahoma

- During 2019, Epsilon's realized price for all Oklahoma production was $3.01 per Mcfe, a 21% decrease over 2018.
- Total production for 2019 included natural gas, oil, and other liquids and was 0.29 Bcfe, as compared to 0.35 Bcfe during 2018.
- We participated in the drilling of 2 gross (0.79 net) wells during 2019. One well (0.10 net to Epsilon) was

completed and turned to production in December. Completion operations for the second well were postponed due to a significant decrease in NGL and oil prices. The well will be considered for completion when commodity prices have recovered enough to generate an attractive return on the incremental capital required for the completion operation.

Business highlights of 2018

Operational Highlights

Marcellus Shale—Pennsylvania

- During the year ended December 31, 2018, Epsilon's realized natural gas price was $2.51 per Mcf, an 18% increase from the year ended, December 31, 2017.
- Total year ended December 31, 2018, production was 7.3 Bcf of natural gas net to our revenue interest in Pennsylvania, as compared to 8.9 Bcf in 2017.
- We participated in the drilling and completion of 4 gross (0.39 net) upper Marcellus wells during 2018. The wells were turned to production in February 2019.
- Gathered and delivered 100.1 Bcf gross (35.0 Bcf net to Epsilon's interest) during the year, or 274 MMcf/d through the Auburn System which represents approximately 83% of designed throughput capacity

NW Stack Trend—Oklahoma

- During 2018, Epsilon's realized price for all production was $3.83 per Mcfe.
- Total production for 2018 included natural gas, oil, and other liquids and was 0.35 Bcfe.
- We participated in the drilling of 3 gross (0.02 net) wells in the Anadarko basin during 2018. Two of the wells were completed with one well being turned to production in June, and the second in August.

Properties

As of December 31, 2019, Epsilon's 78,101 gross (13,100 net) acres are all located in the United States and include 269 gross (59.51 net) wells.

	Gross[1]	Net[2]
Producing Wells		
Oil	8	1.55
Gas	152	30.75
Oil & Gas	67	14.77
Total Producing Wells	227	47.07
Non-producing Wells	42	12.44
Total Wells	269	59.51

Acreage

As of December 31, 2019, our leasehold inventory consisted of the following acreage amounts, rounded to the nearest acre:

	Gross[1]	Net[2] [3]
Developed Acres		
Pennsylvania	8,097	4,130
Oklahoma	6,723	702
Mississippi	627	376
	15,447	5,207
Undeveloped Acres		
Pennsylvania	—	—
Oklahoma	62,654	7,893
Mississippi	—	—
	62,654	7,893
Total Acres		
Pennsylvania	8,097	4,130
Oklahoma	69,377	8,594
Mississippi	627	376
Total acres	78,101	13,100

(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, 2019 and 2018.

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," of 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, 2019 and 2018, respectively, follows:

Revenues ($000)	Year ended December 31, 2019	2018
Natural gas revenue	**$ 16,945,302**	**$ 19,031,422**
Volume (MMcf)	7,757	7,563
Avg. Price ($/Mcf)	$ 2.18	$ 2.52
PA Exit Rate (MMcfpd)	30.5	21.2
Oil and other liquids revenue	**$ 424,661**	**$ 671,221**
Volume (MBO)	14.5	17.1
Avg. Price ($/Bbl)	$ 29.24	$ 39.31
Gathering system revenue	**$ 9,320,373**	**$ 9,981,562**
Total Revenues	**$ 26,690,336**	**$ 29,684,205**

Gathering System Operations

Epsilon Energy USA is the 100% owner of Epsilon Midstream, which owns a 35% undivided interest in the Auburn Gas Gathering System, or 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, Epsilon Energy, Equinor USA Onshore Properties, Inc., and Chesapeake Energy, Inc. 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 gas gathering system (“Auburn GGS”) is determined by a cost of service model whereby the Anchor Shippers in the system 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 2026, prior to the end of the initial period on December 31, a new agreement governing rates will be negotiated between the Anchor Shippers and the gathering system owner.

The Auburn GGS consists of 43.9 miles of gathering pipelines, a small auxiliary compression facility and a main compression facility with three dehydration units and three Caterpillar 3612 compression units. Design capacity of the Auburn compression facility, or the Auburn CF, is approximately 330,000 Mcf, per day. 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.

Revenues from the Auburn GGS are earned primarily from Anchor Shippers, Epsilon Energy USA, Equinor USA Onshore Properties, Inc. and Chesapeake Energy, Inc. Additional but less significant revenues are earned from Chief Oil & Gas LLC. Revenues derived from Epsilon’s production which have been eliminated from gathering system revenues amounted to $1.2 million and $1.1 million, respectively, for the years ended December 31, 2019 and 2018.

During years ended December 31, 2019 and 2018, the Auburn GGS delivered 87.8 Bcf and 100.1 Bcf respectively, of natural gas, or 241 and 274 MMcf per day.

Proved Reserves

Per our reserve report prepared by independent petroleum consultants, DeGolyer and MacNaughton, our estimated proved reserves as of December 31, 2019, are summarized in the table below. See Risk Factors for information relating to the uncertainties surrounding these reserve categories.

	Natural Gas MMcf	Oil and other Liquids MBbl
Pennsylvania-Marcellus Shale		
Proved developed producing	65,774.2	—
Proved undeveloped	55,383.8	—
Total Pennsylvania proved reserves	121,158.0	—
Oklahoma-Anadarko Basin		
Proved developed producing	1,383.7	34.8
Proved undeveloped	1,619.2	81.2
Total Oklahoma proved reserves	3,003.0	116.1
Total proved reserves at December 31, 2019	124,160.9	116.1

We have not engaged in any exploration capital spending in 2019 or 2018. At this time, the Company is on track to develop our proved undeveloped properties within 5 years. Our development capital spending to convert proved undeveloped reserves to proved developed reserves for the periods indicated is as follows:

- In 2019 in Pennsylvania, 4 gross (1.07 net) wells were drilled and completed. (Net development capital $5.6 million). Reserves of 9.7 Bcf for these wells were reclassified as proved developed producing as these wells were turned online in October. Additionally, the 4 gross (0.39 net) wells drilled in 2018 were completed (Development capital $1.6 million) and turned online in February 2019. These wells added another 3.1 Bcf of reserves.

- In 2019 in Oklahoma, 2 gross (0.79 net) wells were drilled (Development capital $3.13 million). One was completed and went online in October, the other is waiting on completion.

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 Executive 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. Reserves are reviewed and approved internally by our Chief Executive Officer on a semi-annual basis. Our Chief Executive Officer holds a Bachelor of Science degree in Chemical Engineering has studied Petroleum Engineering courses on a Masters Level and completed a Masters in Business Administration. He has over 37 years of experience in various positions in the global natural gas and oil business, primarily holding positions in the areas of reservoir development strategy, property valuations, completions and production optimization. He has also been managing the allocation of capital in natural gas and oil investments and appraising the values of those assets on a quarterly basis with Domain Energy Advisors since January 2005. The reserve information in this report is based on estimates prepared by DeGolyer and MacNaughton, our independent engineering firm. The person responsible for preparing the reserve report, Gregory Graves, is a Registered Professional Engineer (No.70734) in the State of Texas and a Senior Vice President of the firm. Mr. Graves graduated from the University of Texas at Austin with a degree in Petroleum Engineering, and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, and has prepared estimates of natural gas and oil reserves since joining DeGolyer and MacNaughton in 2006. 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 Executive Officer to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. Additionally, we have an independent member of the Board interview the reserve engineering firm to ensure the independent nature of the appraisal.

Marketing and Major Customers

Natural gas marketing is extremely 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 Compression Facility.

For the year ended December 31, 2019, we sold natural gas to 29 unique customers. EQT Energy LLC, and Spotlight Energy LLC each accounted for 10% or more of our total revenue. For the year ended December 31, 2018, we sold natural gas to 28 unique customers. Citadel Energy Marketing LLC, and Spotlight Energy LLC each accounted for 10% or more of our total revenue.

Geographic Locations of Operations

Through December 31, 2019, our primary source of revenue originated 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. To this end, we have begun to acquire leases in the Anadarko basin and to expand our holdings in Pennsylvania.

Competition

In both the Marcellus Basin and the Anadarko Basin, we operate in a competitive environment for acquiring leases, developing reserves and marketing production. In most instances, we are a substantially smaller organization than our competitors both in terms of our personnel as well as our financial capability. This size differential relative to our competitors could disadvantage us, particularly in regard to accessing capital markets, acquiring technical expertise, and attracting and retaining talented personnel.

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.

In our gas gathering activity in the Marcellus, the competition for customer shippers on our Auburn GGS is significant. Although the Auburn GGS has three dedicated shippers (of which we are one), there is non-dedicated acreage within the footprint of the gathering system. However, the Auburn GGS currently serves only one non-anchor shipper, and there is no guarantee that we will be able to attract other customers to the system.

Our Status as an Emerging Growth Company

We are an “emerging growth company,” as defined in 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 $1.07 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 sale of common equity securities under an effective Securities Act registration statement;

- 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 Securities and Exchange Commission, or 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, 2019, we had eight 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.

Legal Proceedings

We are not aware of any pending or threatened legal proceedings to which we may be a party. From time to time, we may become involved in litigation related to claims arising from the ordinary course of our business.

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, 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.

In August 2015, the EPA issued final rules outlining the Clean Power Plan ("CPP"), which was developed in accordance with the Obama Administration's Climate Action Plan. Under the CPP, carbon pollution from power plants was set to be reduced over 30% below 2005 levels by 2030. In 2017, EPA completed a review of the Clean Power Plan pursuant to President Trump's Energy Independence Executive Order. As a result, EPA proposed the repeal of the CPP, based in part on its interpretation of Section 111(d) of the Clean Air Act. In August 2018, the Trump Administration, through the EPA, issued its proposed replacement of the CPP, entitled the Affordable Clean Energy rule.

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. These standards expand the previously issued NSPS requirements. In February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. 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. However, in September 2018, the BLM published a final rule that codifies the BLM's prior approach to venting and flaring. The rule rescinding the November 2016 final rule has been challenged in federal court.

Internationally, in April 2016, the United States joined other countries in entering into a non-binding agreement France for nations to limit their GHG emissions through country-determined reduction goals every five years beginning in 2020 (the "Paris Agreement"). However, in August 2017, the U.S. State Department announced its intention to withdraw from the Paris Agreement.

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.'' Effective as of the close of trading on March 15, 2019, Epsilon voluntarily delisted its common shares from the Toronto Stock Exchange. The last reported sales price of our common shares on the NASDAQ Global Market on March 17, 2020 was $2.70 per share.

Shareholders. We had approximately 1,400 shareholders of record as of December 31, 2019.

Dividends. We have not declared or paid any cash or stock dividends on our common shares since our inception and do not anticipate declaring or paying any cash or stock dividends in the foreseeable future.

Securities Authorized for Issuance under Equity Incentive Plans.

At December 31, 2019, 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	245,000	$ 5.27	755,000
Common shares under 2017 Stock Compensation Plan	346,499	$ 3.76	653,501

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

	As at December 31, 2019		As at December 31, 2018	
	Number of Options Outstanding	Weighted Average Exercise Price	Number of Options Outstanding	Weighted Average Exercise Price
Balance at beginning of period	290,750	$ 5.02	330,750	$ 5.14
Exercised	(25,000)	2.17	—	—
Expired/Forfeited	(20,750)	$ 5.37	(40,000)	6.00
Balance at period-end	245,000	$ 5.27	290,750	$ 5.02
Exercisable at period-end	206,670	$ 5.32	210,249	$ 5.02

As of December 31, 2019, we had no warrants or other common share-related rights outstanding.

At December 31, 2019, we were authorized to issue Common Shares in an amount up to 100% of the participant's compensation paid by the Company in consideration of the participant's service for the current year divided by the market price of the Common Shares on the NASDAQ at the date of issuance of the Common Shares in the current year. As of that date, we had 346,499 unvested common shares granted. The following table sets out the number of common shares to be issued upon vesting over the next three years pursuant to our share compensation plan and the weighted average market price at date of issue for outstanding shares for the periods indicated:

	As at December 31, 2019		As at December 31, 2018	
	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	282,833	$ 4.53	162,500	$ 4.59
Granted	184,500	3.30	174,500	4.49
Vested	(106,834)	4.54	(54,167)	4.60
Forfeited	(14,000)	4.43	—	—
Balance non-vested Restricted Stock at end of period	346,499	$ 3.76	282,833	$ 4.53

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 proved 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, 2019 and 2018, or the DeGolyer Reserve Reports, 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 and Capital Resources

Currently, our activity is highly concentrated to one product in one area. Although we are attempting to expand our operations to other areas with multiple products, we may not be successful in these other areas.

An investment in us is subject to certain risks. There are numerous factors that may affect the success of our business that are beyond our control including local, national and international economic and political conditions. Our business involves a high degree of risk, which a combination of experience, knowledge and careful evaluation may not overcome. Through December 31, 2019, our primary source of revenue originated 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. To this end, we have begun to acquire leases in the Anadarko basin and to expand our holdings in Pennsylvania. Our future depends on being able to successfully fund and develop these assets. There can be no assurance that our business will be successful or that profitability will continue or that we will discover additional commercial quantities of crude oil or natural gas.

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, changes in the political landscape or limitations on spending. An economic downturn and uncertainty may have a negative impact on our business. In 2008, the financial markets collapsed causing the capital markets for the natural gas and oil sector substantial setbacks. As recently as 2015 and 2016, natural gas and oil prices decreased to a point as to make almost all investment in natural gas and oil projects uneconomic. As of March 16, 2020, the one month forward contract for WTI (NYMEX) was $28.70 per Bbl and the one month forward contract for natural gas (NYMEX) was $1.82 per MMBtu. We cannot predict the length and impact of the recent significant downturn in demand and commodity prices as a result of the global COVID-19 crisis and the discord among oil producing nations referred to as OPEC+. 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 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. However, high returns are not guaranteed, and the results of drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, a less predictable future of drilling results in these areas. Ultimately, the success of drilling and completion techniques can only be evaluated as more wells are drilled and production profiles are established over a sufficiently long time period. 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, as a result of less than desirable results in developments we 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 operations are currently geographically concentrated and therefore subject to regional economic, regulatory and capacity risks.

Approximately 96% of our production during fiscal 2019 and 2018 was derived from our properties in the Marcellus 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.

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. Any such instance may offset the return on and value of the common shares.

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

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 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 conventional 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.

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 the holder of our leasehold interests 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 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.

If we are unable to successfully compete with the large number of oil and natural gas producers in our industry, we may not be able to achieve profitable operations.

Oil and natural gas exploration is intensely competitive in all its phases and involves a high degree of risk. We compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas, as well as, for the hiring of skilled industry personnel, contractors and equipment. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than we do. Our ability to increase reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Competition may also be presented by alternate fuel sources.

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 Jumpstart Our Business Startups Act of 2012, or 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 $1.07 billion or more;
- the last day of the fiscal year following the fifth anniversary of our registration on February 14, 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 shareholders parachute provisions (requiring a non-binding shareholder vote to approve golden parachute arrangements for certain executive advisory votes pursuant to the "say on frequency" and "say on pay" provisions (requiring a non-binding shareholder vote to approve compensation of certain executive officers) and the "say on golden officers in connection with mergers and certain other business combinations) of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010; and
- include detailed compensation discussion and analysis in our filings under 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 expend, 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. 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 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 obtain new supplies. 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.

The gathering rate on the Auburn Gas Gathering System 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 gas gathering system ("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 2026, prior to the end of the initial period on December 31, a new agreement governing rates will be negotiated between the Anchor Shippers and the gathering system owners. All else being equal, if total throughput on the system is lower than forecasted, the gathering rate will increase. If the gathering rate on the Auburn GGS increases, it could render drilling uneconomic for shippers or result in shippers allocating capital to more competitive areas which could result in further increases in the gathering rate. Although the Anchor Shippers have dedicated their reserves to the Auburn GGS, they are under no obligation to develop reserves if they determine that development is uneconomic.

Because of the large supply of gas, and limited availability of transportation out of the Marcellus 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, 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 gas gathering system 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 or complete halt to the development of reserves will impact our financial results, cash flows, access to capital and ability to maintain our gas gathering system.

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 maintain and expand our natural gas gathering businesses depends on the level of drilling and production by Anchor Shippers and third parties in our gathering area. 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 other Anchor Shippers or third-party natural gas reserves connected to our systems and compression facilities. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. 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.

We are not a party to any pending or threatened legal proceedings. From time to time, we may become involved in litigation related to claims arising from the ordinary course of our business.

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 December 31, 2019, our Board made a grant to our directors, executive officers and employees, entitling them to receive an aggregate of 247,000 Common Shares which shares will 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 period. The awards were made under the Share Compensation Plan in accordance with Rule 701 promulgated under the Securities Act.

Commencing on May 20, 2019, the Company entered into a share repurchase program on the NASDAQ conducted in accordance with Rule 10b-18 promulgated under the Securities Exchange Act of 1934. The Company is authorized to repurchase up to 1,367,762 of its outstanding common shares, representing 5% of the outstanding common shares of Epsilon as of May 20, 2019, for an aggregate purchase price of not more than $2.5 million. The program will end on May 19, 2020 unless the maximum amount of common shares is purchased before then or Epsilon provides earlier notice of termination.

Repurchases may be made at management's discretion from time to time through the facilities of the NASDAQ Global Market. The price paid for the common shares will be, subject to applicable securities laws, the prevailing market price of such common shares on the NASDAQ Global Market at the time of such purchase. The Company intends to fund the purchase out of available cash and does not expect to incur debt to fund the share repurchase program.

The following table contains information about our repurchase of equity securities during the year ended December 31, 2019:

	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
Beginning balance at May 20, 2019			—	1,367,762
May 2019	16,148	$ 4.17		
June 2019	221,041	$ 4.12		
July 2019	55,112	$ 3.90		
August 2019	56,432	$ 3.66		
September 2019	14,797	$ 3.79		
October 2019	42,307	$ 3.38		
November 2019	290,259	$ 3.41		
Total for the year ended December 31, 2019	696,096	$ 3.72	696,096	671,666

ITEM 6. SELECTED FINANCIAL DATA.

The table below presents our selected historical consolidated financial data for the years ended December 31, 2019 and 2018. The selected historical consolidated financial data as of and for the years ended December 31, 2019 and 2018 have been derived from our audited consolidated financial statements, which have been audited by BDO USA, LLP, an independent registered public accounting firm. The selected historical consolidated financial data set forth below should be read in conjunction with the section titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" for such periods and our consolidated financial statements and related notes. Our consolidated financial statements included in this report have been prepared in accordance with United States generally accepted accounting principles, or GAAP.

To meet NASDAQ listing standards, the shareholders of the Company, on December 19, 2018, approved a Consolidation (reverse stock split) of the issued and outstanding common shares on the basis of one (1) new common share for up to every existing two (2) common shares issued and outstanding immediately prior to the Consolidation. The common shares commenced trading on a post-Consolidation basis on the TSX on December 24, 2018. All share amounts and per share data are presented in these statements on a post-Consolidation basis.

	Year ended December 31,	
	2019	2018
Income Statement Data		
Revenues	$ 26,690,336	$ 29,684,205
Cost of revenues	7,908,803	7,945,677
Development geological and geophysical expenses	83,748	—
Depreciation, depletion, amortization and accretion	7,387,681	7,181,753
Gain on sale of property	(1,375,000)	189,142
General and administrative expense	4,500,000	4,935,738
Income from operations	8,185,104	9,431,895
Other income (expense)	4,290,384	(2,027,410)
Income tax expense	3,777,489	742,425
Net income	$ 8,697,999	$ 6,662,060
Net income per share, basic	$ 0.32	$ 0.24
Net income per share, diluted	$ 0.32	$ 0.24
Weighted average number of shares outstanding, basic	27,129,430	27,462,788
Weighted average number of shares outstanding, diluted	27,129,430	27,474,125

	As of December 31,	
	2019	2018
Balance Sheet Data		
Cash and cash equivalents	$ 14,052,417	$ 14,401,257
Oil and gas properties	62,611,733	54,542,839
Gathering system properties	11,483,535	12,903,274
Total assets	97,669,203	87,897,709
Total long-term liabilities	13,807,341	11,614,432
Total shareholders' equity[(1)]	76,362,994	69,944,087

(1) No cash dividends were declared or paid during the periods presented.

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 at December 31, 2019 and 2018 and for the years then ended together with accompanying notes.

Overview

We are 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. Our primary areas of operation are Pennsylvania and Oklahoma. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs.

Substantially all of the production from our Pennsylvania acreage (4,130 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 of the system. We own a 35% interest in the system which is operated by a subsidiary of Williams Partners, LP. In 2019, we paid $1.2 million to the Auburn GGS to gather and treat our 7.6 Bcf of natural gas production in Pennsylvania ($1.1 million to the Auburn GGS to gather and treat our 7.3 Bcf in 2018).

At December 31, 2019 our total estimated net proved reserves were 124,161 million cubic feet (MMcf) of natural gas reserves and 116,053 barrels (Bbl) of oil and other liquids, and we held leasehold rights to approximately 78,101 gross (13,100 net) acres. We have natural gas production in Pennsylvania, and natural gas and oil production from our operated and non-operated wells in Oklahoma.

Business Strategy

Our business strategy is to manage the cash flow generated from our producing leasehold and midstream assets in a manner where the risked capital allocation provides attractive rates of return. Our remaining inventory of drillable locations within existing leasehold is sufficient to maintain this cash flow for several years at capital expenditure levels well within the yearly free cash flow generated from these assets. In addition, we seek to identify attractive onshore natural gas and oil properties in the United States, to acquire a leasehold interest and to develop the leasehold interest with the goal of deploying capital at attractive rates.

The core Marcellus Shale is one of the most attractive dry gas resources in the lower United States and has attracted significant development capital. Well productivity has improved dramatically for many years resulting in increasing initial production rates and gas recoveries. The resulting supply of natural gas has at times stressed the transportation infrastructure of the Northeast US and exacerbated the local price discount to Henry Hub. In many other basins throughout the US, the increase in natural gas production has outpaced demand. This market condition has resulted in historically weaker natural gas prices for the benchmark index Henry Hub.

The operating environment remains challenging in Northeast Pennsylvania. In the Marcellus, we implemented a number of initiatives to enhance the value of our core assets in the Marcellus including a comprehensive review of well spacing and completion productivity for both the Lower and Upper Marcellus, and we are working with our well operators to increase operating efficiency. In addition, we continue to work closely with our gathering system partners in order to enhance operational safety and to preserve and grow the long-term value of our gathering system assets.

The major producers in the Appalachian region are under tremendous pressure from capital markets to demonstrate capital discipline and control costs. Several major producers have announced reduced capital programs to balance the supply-demand for the commodity. Accordingly, we expect local production to decline modestly throughout the second half of 2020. We cannot, however, predict the duration of a global recession and its impact on oil and gas demand and commodity prices. Our target is to maintain our current production level or grow modestly, but only if natural gas prices improve and the capital deployed can achieve our internal hurdle rate of return.

In the longer term, we believe natural gas prices will become more constructive due to a moderating of supply and incremental demand from LNG exports, exports to Mexico and further coal to gas switching for domestic electrical power generation. Specifically, LNG export capacity is expected to more than double from the current ~ 8.5 Bcf/d to 17 Bcf/d by 2024 based only on facilities currently commissioning or under construction.

In the Northwest STACK, the Company chooses to not deploy capital due to depressed natural gas liquids and natural gas pricing. However, the leases are held by production which provides a long-term right to develop additional sales when commodity prices appear attractive. In the interim, we intend to monitor development activities from offset operators in our area very closely in an effort to further appraise our leasehold interest without risking capital.

We realized net income of $8.5 million during 2019 as compared to net income of $6.7 million for 2018. At December 31, 2019, our total estimated net proved reserves of natural gas were 124,161 MMcf, an increase of 5,045 MMcf from December 31, 2018. Our standardized measure of discounted future net cash flows as of December 31, 2019 and

2018 was $49.6 million and $59.1 million, respectively. This measure of discounted future net cash flows does not include any estimate for future cash flows generated by Epsilon's 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, 2019, revenues decreased $3.0 million, or 10.9%, to $26.7 million from $29.7 million during the same period in 2018.

Revenue and volume statistics for the years ended December 31, 2019 and 2018 were as follows:

	Year ended December 31, 2019	Year ended December 31, 2018
Revenues		
Natural gas revenue	**$ 16,945,302**	**$ 19,031,422**
Volume (MMcf)	7,757	7,563
Avg. Price ($/Mcf)	$ 2.18	$ 2.52
PA Exit Rate (MMcfpd)	30.5	21.2
Oil and other liquids revenue	**$ 424,661**	**$ 671,221**
Volume (MBO)	14.5	17.1
Avg. Price ($/Bbl)	$ 29.24	$ 39.31
Gathering system revenue	**$ 9,320,373**	**$ 9,981,562**
Total Revenues	**$ 26,690,336**	**$ 29,684,205**

We earn gathering system revenue as a 35% owner of the Auburn Gas Gathering system. This revenue consists of fees paid by Anchor Shippers and 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. For the year ended December 31, 2019, approximately 87% of the Auburn GGS revenues earned are gathering fees, while 13% are compression fees. Third party customers represent approximately 11% of gathering revenues and 4% of compression revenues. For the year ended December 31, 2018, approximately 86% of the Auburn GGS revenues earned were gathering fees, while 14% were compression fees. Third party customers represent approximately 11% of gathering revenues and 5% of compression revenues. Revenues derived from transporting and compressing Epsilon's production which have been eliminated from gathering system revenues amounted to $1.2 million and $1.1 million respectively for the year ended December 31, 2019 and 2018.

Upstream revenue consists primarily of revenues from Pennsylvania, but immaterial Oklahoma revenues are also included. For the year ended December 31, 2019 upstream revenue decreased by $2.3 million, or 11.8%, over 2018, primarily as a result of lower natural gas prices, offset slightly by higher volumes. Volumes were higher during 2019, despite of lower prices, because of the completion of 4 wells drilled during 2018 that went online in February 2019, and the drilling and completion of 4 additional wells that went online in October 2019. The end of the year daily production rate for gas in Pennsylvania was 30.5 MMcf.

Gathering system revenue decreased $0.7 million, or 6.6%, during the year ended December 31, 2019, due to a 12.3% decrease in the volumes flowing through the system. This was partially offset by a higher gathering rate and lower volumes of imported gas from other inter-connected systems (crossflow). The Auburn GGS is subject to a cost of service model, whereby the Anchor Shippers dedicate acreage and reserves to the Auburn GGS. In exchange for this dedication, the owners of the Auburn system agree to a fixed rate of return on capital invested which cannot be exceeded. Therefore, rather than being subject to a fixed gathering rate, the Shippers are subject to a fluctuating gathering rate which is re determined annually in order to produce the contractual return on capital to the Auburn GGS owners. The term of the model is fixed from 2012 to 2026. Each year, actual throughput, revenue, operating expenses and capital are captured in the model, and the remaining years are forecasted. The model then iterates for a gathering rate that yields the contractual rate of return. All else being equal, to the extent that throughput is higher or capital is lower than the preceding year's forecast, the gathering rate will decline.

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, 2019 and 2018:

	Year ended December 31,	
	2019	**2018**
Lease operating costs	$ 6,571,394	$ 6,665,856
Gathering system operating costs	1,337,409	1,279,821
	$ 7,908,803	**$ 7,945,677**
Upstream operating costs—Total $/Mcfe	0.84	0.87
Gathering system operating costs $ / Mcf	0.11	0.10

Upstream operating costs include costs primarily from Pennsylvania, but insignificant Oklahoma costs have also been included in the total, however the costs are not significant. 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.

Gathering system operating costs consist primarily of rental payments for the natural gas fueled compression units. Other significant gathering system operating costs include chemicals (to prevent corrosion and to reduce water vapor in the gas stream), saltwater disposal, measurement equipment / calibration and general project management. The gathering system operating costs and the associated $/Mcf reported include the effects of elimination entries to remove the gas gathering fees billed by the gas gathering system operator to Epsilon's upstream operations, and the volume associated with those fees. The elimination entries amounted to $1.2 million and $1.1 million for the years ended December 31, 2019 and 2018, respectively (see Note 12, "Operating Segments," of the Notes to Consolidated Financial Statements).

For the year ended December 31, 2019, upstream operating costs decreased by $0.09 million, or 1.4% from the same period in 2018. The decrease in total cost was mainly due to the decrease in volumes produced for the first 10 months of the year. The $/Mcfe also decreased, primarily due to a decrease in costs related to remediation costs related to a saltwater spill on one of our pads. Production increased when 4 wells went online in October, but operating costs did not increase significantly.

Gathering system costs for the year ended December 31, 2019 increased $0.06 million, or 4.5% over the same period in 2018 despite lower throughput volumes due to increased chemical expenses and timing of maintenance expenses.

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

	Year ended December 31,	
	2019	**2018**
Depletion, depreciation, amortization and accretion	**$ 7,387,681**	**$ 7,181,753**

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. At this time, the Company has only minimal leasehold acquisition costs, and only in Oklahoma. 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. The depletion for the first three quarters of the next year is based on the reserve report prepared at the end of the previous year, taking into consideration the limited development of the reserves over these time periods. The fourth quarter depletion is calculated using the reserve volumes from the reserve report prepared as of December 31 of the current year.

Depreciation expense includes amounts pertaining to our office furniture and fixtures, leasehold improvements, computer hardware and software. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, ranging from 3 to 7 years.

Accretion expense is related to the asset retirement costs.

As discussed above, DD&A expense for the first three quarters is calculated based on the reserve report from the prior year. During the year ended December 31, 2019, DD&A expense increased by $0.2 million, or 2.9%, compared to the same period in 2018 mainly due to the addition of eight new wells. Four wells for the full year and four wells for the last three months of the year. Even with the substantially increased production in the fourth quarter, DD&A only increased slightly as a result of a lower fourth quarter DD&A rate related primarily to the reserves added with the new wells.

Gain (Loss) on Sale of Properties

	Year ended December 31,	
	2019	**2018**
Gain (loss) on sale of properties	**$ (1,375,000)**	**$ 189,142**

For the year ended December 31, 2019 gain (loss) on sale of properties consisted of a gain on the sale of a few stranded, non-producing leases in Pennsylvania. For the year ended December 31, 2018 gain (loss) on sale of properties consisted of a loss taken for the writing off of six wells that do not belong to Epsilon.

General and Administrative ("G&A")

	Year ended December 31,	
	2019	**2018**
General and administrative	**$ 4,500,000**	**$ 4,935,738**

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.

The G&A expenses decreased by $0.4 million, or 8.4%, during the year ended December 31, 2019 from the same period in 2018, mainly due to decreased consulting and legal costs required for the effort to obtain a listing on a major U.S. stock exchange spent in 2018. We expect expenses to continue to decrease in 2020 as our efforts to be listed on a major U.S. stock exchange were successful.

Interest Expense

	Year ended December 31,	
	2019	**2018**
Interest expense	**$ 115,356**	**$ 140,615**

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

Interest expense decreased during the year ended December 31, 2019 from $0.14 million for the year ended December 31, 2018 to $0.12 million, or 18.0%. This was due to the paying off of the revolving line of credit in December 2018. Interest expense for 2019 consists primarily of commitment fees as we did not access our line of credit during 2019.

Net gain (loss) on commodity contracts

	Year ended December 31,	
	2019	**2018**
Gain (loss) on derivative contracts	**$ 4,246,057**	**$ (1,938,465)**

During the years ended December 31, 2019 and 2018, we entered into fixed price swap and basis swap derivative contracts. The amounts recorded represent the fair value changes on our derivative instruments during the period. During the periods, the Company received $1,949,232 and paid $1,381,898, respectively, on the settlement of contracts due to the change in commodity prices.

The realized losses during 2018 were almost entirely due to NYMEX Henry Hub ("NYMEX HH") swaps that settled out-of-the-money as Henry Hub prices moved higher throughout the year. At December 31, 2018, however, the unrealized losses in the derivative contracts were almost entirely attributable to out-of-the-money basis swaps. In January, March and October of 2019, the Company added Henry Hub and basis swaps totaling 2.22 Bcf with expirations during the year ended December 31, 2019. NYMEX HH prices generally declined throughout the year resulting in large realized gains on both the Henry Hub swaps that were held at December 31, 2018 and also the HH swaps that were added during 2019.

Furthermore, by December 31, 2019, substantially all of the gains in the unsettled contracts held was due to in-the-money NYMEX HH swaps. These NYMEX HH swaps totaling 5.26 Bcf were added to the hedge portfolio throughout 2019.

Other Income (Expense)

	Year ended December 31,	
	2019	2018
Other income (expense)	**$ 804**	**$ 39,583**

For the year ended December 31, 2019 other income consisted primarily of net foreign currency gains. For the year ended December 31, 2018 other expense consisted primarily of income from state income tax refunds received.

Net Income Compared to Adjusted EBITDA

	Year ended December 31,	
	2019	2018
Net income	$ 8,697,999	$ 6,662,060
Add Back:		
Net interest (income) expense	(43,523)	128,528
Income tax expense	3,777,489	742,425
Depreciation, depletion, amortization, and accretion	7,387,681	7,181,753
Stock based compensation expense	510,460	330,232
(Gain) loss on derivative contracts net of cash received or paid on settlement	(2,296,825)	556,567
Foreign currency translation (gain) loss	(437)	(1,330)
Adjusted EBITDA	$ 18,032,844	$ 15,600,235

Epsilon defines 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. Epsilon has included Adjusted EBITDA as a supplemental disclosure because its management believes that EBITDA provides useful information regarding its 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 the Company 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 Adjusted EBITDA to net income, 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

Our primary source of cash during the years ended December 31, 2019 and 2018 was funds generated from operations. In addition to operations, cash was received from the sale of leases in Pennsylvania and used for acquisition and development of natural gas and oil properties, and the buyback of common shares through our share repurchase program as discussed in Note 6 of our financial statements. During the year ended December 31, 2018, funds were mainly used for operations, income tax prepayments, development expenditures, and the repayment of the revolving line of credit.

At December 31, 2019, we had a working capital surplus of $16.3 million, an increase of $2.7 million over the $13.6 million surplus at December 31, 2018. The surplus increased over the last year because of the cash that is continually being generated by operations, cash received from the settlement of derivative contracts and the previously discussed sale of leases in Pennsylvania.

Year ended December 31, 2019 compared to 2018

During the year ended December 31, 2019, $13.0 million was provided by our operating activities, compared to $10.1million in 2018, a $2.9 million, or 28%, increase. The increase was mainly due to the increase in net income combined with the collection of receivables outstanding at December 31, 2018 and cash received on the settlement of derivative contracts.

We used $10.5 million for investing activities during the year ended December 31, 2019. This was spent primarily on leasehold and development costs targeting increasing production in Pennsylvania and Oklahoma, and the acquisition of unproved properties in Oklahoma, all offset by the $1.4 million received on the sale of leases in Pennsylvania. During the same period of 2018, we used $2.0 million, primarily for leasehold costs in anticipation of new lease purchases and a drilling program.

We used $2.8 million in financing activities during the year ended December 31, 2019 for the buyback and cancelation of shares of Epsilon stock. The $3.6 million of cash used for financing activity during the year ended December 31, 2018 was used for the payoff of our revolving line of credit and the buyback and cancelation of shares of Epsilon stock.

Credit Agreement

In addition, we have a senior secured credit facility which includes a total commitment of up to $100 million. The current effective borrowing base is $23 million, which is subject to semi-annual redetermination. There are currently no borrowings under the facility. Borrowings from the Facility may be used for the acquisition and development of oil and gas properties, investments in cash flow generating assets complimentary to the production of oil and gas, and for letters of credit and other general corporate purposes. Upon each advance, interest is charged at the highest of a) rate of LIBOR plus an applicable margin (2.75%-3.75% based on the percent of the line of credit utilized), b) the Prime Rate, or c) the sum of the Federal Funds Rate plus 0.5%. Effective January 7, 2019 the agreement was amended to extend the maturity date to March 1, 2022.

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

- Interest coverage ratio greater than 3 based on income adjusted for interest, taxes and non-cash amounts.

- Current ratio, adjusted for line of credit amounts used and available and non-cash amounts, greater than 1.

- Leverage ratio less than 3.5 based on income adjusted for interest, taxes and non-cash amounts.

We were in compliance with the financial covenants of the agreement as of December 31, 2019 and December 31, 2018 and expect to be in compliance for the next 12 months. We expect to remain in compliance as we currently have no borrowings under the facility and have funded all operations for 2019 out of operating cash flow and cash on hand and expect to continue to do so through 2020.

Derivative Transactions

We have 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, 2019, our outstanding natural gas commodity swap contracts consisted of the following:

Derivative Type	Volume (Mmbtu)	Weighted Average Price ($/MMbtu) Swaps	Weighted Average Price ($/MMbtu) Basis Differential	Fair Value of Asset December 31, 2019
2019				
Fixed price swap	4,637,500	$ 2.71	$ —	2,001,496
Basis swap	4,637,500	$ —	$ (0.43)	(1,694)
	9,275,000			$ 1,999,802

Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2019:

	Payments Due by Period			
	Total	Less than 1 Year	1 – 3 Years	Greater than 3 Years
Derivative liabilities[1]	164,538	164,538	—	—
Asset retirement obligation, undiscounted	8,880,732	—	—	8,880,732
Capital expenditure commitments	1,974,241	—	1,974,241	—
Operating leases	319,672	90,553	211,112	18,007
Total future commitments	$ 11,339,183	$ 255,091	$ 2,185,353	$ 8,898,739

(1) The liability balance shown represents the gross liability balance of derivative contracts before being offset by contracts in an asset position.

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 have been included in the contractual obligations table above.

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, 2019 and 2018, we had no off-balance sheet arrangements.

Summary of Critical Accounting Policies and 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.

Successful Efforts Accounting

We use the successful efforts method of accounting for natural gas and oil operations. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. 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.

Gathering System

We hold an undivided interest in a gas gathering system asset that supports our Pennsylvania operations. We account for the costs and revenue from this system using the proportionate consolidation method.

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.

Depreciation and amortization of other property, plant and equipment is calculated on a straight-line basis over the estimated useful life of the asset.

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 unamortized capitalized cost 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 unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC 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.

Under ASC 360, 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 described in the Fair Value Measurement Topic of the ASC, 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 Obligation ("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. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires judgment. 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 of the 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 US 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, 2019 and 2018, 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 Epsilon 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, 2019 and 2018, and the consolidated statements of operations and comprehensive income, changes in shareholders’ equity and cash flows for years ended December 31, 2019 and 2018 included in this annual report have been prepared in accordance with U.S. GAAP.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

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, 2019 and 2018, and the related consolidated statements of operations and comprehensive income, changes in shareholders' equity, and cash flows for each of the two years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2019, 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 consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures 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 18, 2020

EPSILON ENERGY LTD.

Consolidated Balance Sheets

	December 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 14,052,417	$ 14,401,257
Accounts receivable	4,296,917	5,042,134
Fair value of derivatives	1,999,802	—
Prepaid income taxes	1,641,501	205,711
Other current assets	433,687	244,233
Total current assets	22,424,324	19,893,335
Non-current assets		
Property and equipment:		
Oil and gas properties, successful efforts method		
Proved properties	130,819,256	118,851,574
Unproved properties	21,047,512	19,498,666
Accumulated depletion, depreciation, and amortization	(89,255,035)	(83,807,401)
Total oil and gas properties, net	62,611,733	54,542,839
Gathering system	41,445,225	41,040,847
Accumulated depletion, depreciation, and amortization	(29,961,690)	(28,137,573)
Total gathering system, net	11,483,535	12,903,274
Land	375,314	—
Buildings and other property and equipment, net	211,879	—
Total property and equipment, net	74,682,461	67,446,113
Other assets:		
Restricted cash	561,294	558,261
Prepaid drilling costs	1,124	—
Total non-current assets	75,244,879	68,004,374
Total assets	$ 97,669,203	$ 87,897,709
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable trade	$ 2,828,495	$ 1,762,586
Royalties payable	1,306,922	1,300,539
Accrued capital expenditures	627,356	522,437
Accrued gathering fees	373,929	300,301
Other accrued liabilities	858,188	2,156,304
Fair value of derivatives	—	297,023
Asset retirement obligation	1,503,978	—
Total current liabilities	7,498,868	6,339,190
Non-current liabilities		
Asset retirement obligation	1,405,877	1,625,154
Deferred income taxes	12,401,464	9,989,278
Total non-current liabilities	13,807,341	11,614,432
Total liabilities	21,306,209	17,953,622
Commitments and contingencies (Note 10)		
Shareholders' equity		
Common shares, no par value, unlimited shares authorized and 26,790,985 issued and outstanding at December 31, 2019 and 27,385,133 shares issued and 27,358,180 shares outstanding at December 31, 2018.	140,808,923	143,705,441
Treasury shares, 26,953 shares issued at December 31, 2018	—	(94,418)
Additional paid-in capital	7,029,488	6,519,028
Accumulated deficit	(81,285,895)	(89,983,894)
Accumulated other comprehensive income	9,810,478	9,797,930
Total shareholders' equity	76,362,994	69,944,087
Total liabilities and shareholders' equity	$ 97,669,203	$ 87,897,709

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, 2019	2018
Revenues from contracts with customers:		
Gas, oil, NGLs and condensate revenue	$ 17,369,963	$ 19,702,643
Gas gathering and compression revenue	9,320,373	9,981,562
Total revenue	26,690,336	29,684,205
Operating costs and expenses:		
Lease operating expenses	6,571,394	6,665,856
Gathering system operating expenses	1,337,409	1,279,821
Development geological and geophysical expenses	83,748	—
Depletion, depreciation, amortization, and accretion	7,387,681	7,181,753
(Gain) loss on sale/disposal of property	(1,375,000)	189,142
General and administrative expenses:		
Stock based compensation expense	510,460	330,232
Other general and administrative expenses	3,989,540	4,605,506
Total operating costs and expenses	18,505,232	20,252,310
Operating income	8,185,104	9,431,895
Other income (expense):		
Interest income	158,879	12,087
Interest expense	(115,356)	(140,615)
Gain (loss) on derivative contracts	4,246,057	(1,938,465)
Other income (expense)	804	39,583
Other income (expense), net	4,290,384	(2,027,410)
Income before income tax expense	12,475,488	7,404,485
Income tax expense	3,777,489	742,425
NET INCOME	$ 8,697,999	$ 6,662,060
Currency translation adjustments	12,548	(115,306)
NET COMPREHENSIVE INCOME	$ 8,710,547	$ 6,546,754
Net income per share, basic	$ 0.32	$ 0.24
Net income per share, diluted	$ 0.32	$ 0.24
Weighted average number of shares outstanding, basic	27,129,430	27,462,788
Weighted average number of shares outstanding, diluted	27,129,430	27,474,125

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, 2017	27,522,852	$ 144,292,238	—	$ —	$ 6,171,525	$ 9,913,236	$ (96,645,954)	$ 63,731,045
Net income	—	—	—	—	—	—	6,662,060	6,662,060
Stock-based compensation expenses	—	—	—	—	330,232	—	—	330,232
Buyback and retirement of common shares	(137,719)	(586,797)	—	—	17,271	—	—	(569,526)
Buyback of common shares not yet retired	—	—	26,953	(94,418)	—	—	—	(94,418)
Other comprehensive income	—	—	—	—	—	(115,306)	—	(115,306)
Balance at December 31, 2018	27,385,133	$ 143,705,441	26,953	$ (94,418)	$ 6,519,028	$ 9,797,930	$ (89,983,894)	$ 69,944,087
Net income	—	—	—	—	—	—	8,697,999	8,697,999
Stock-based compensation expenses	—	—	—	—	510,460	—	—	510,460
Retirement of common shares	(26,953)	(94,418)	(26,953)	94,418	—	—	—	—
Exercise of stock options	25,000	54,250	—	—	—	—	—	54,250
Buyback and retirement of common shares	(753,196)	(2,856,350)	—	—	—	—	—	(2,856,350)
Restricted stock shares vested	161,001	—	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	12,548	—	12,548
Balance at December 31, 2019	26,790,985	$ 140,808,923	—	$ —	$ 7,029,488	$ 9,810,478	$ (81,285,895)	$ 76,362,994

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

EPSILON ENERGY LTD.

Consolidated Statements of Cash Flows

	Year ended December 31, 2019	Year ended December 31, 2018
Cash flows from operating activities:		
Net income	$ 8,697,999	$ 6,662,060
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	7,387,681	7,181,753
(Gain) loss on sale/disposal of properties	(1,375,000)	189,142
(Gain) loss on derivative contracts	(4,246,057)	1,938,465
Cash received from (paid for) settlements of derivative contracts	1,949,232	(1,381,898)
Stock-based compensation expense	510,460	330,232
Deferred income tax expense (benefit)	2,412,186	(572,405)
Changes in assets and liabilities:		
Accounts receivable	745,217	(1,707,239)
Prepaid income taxes and other current assets	(1,625,244)	(173,513)
Accounts payable, royalties payable and other accrued liabilities	(1,471,460)	(545,286)
Other long-term liabilities	—	(1,615,313)
Net cash provided by operating activities	12,985,014	10,305,998
Cash flows from investing activities:		
Acquisition of unproved oil and gas properties	(596,500)	(260,000)
Acquisition of proved oil and gas properties	—	(4,992)
Additions to unproved oil and gas properties	(952,345)	(1,787,114)
(Additions to) refunds of proved oil and gas properties	(9,411,916)	(22,481)
Additions to gathering system properties	(366,059)	(148,360)
Additions to land, buildings and other fixed assets	(588,325)	—
Prepaid drilling costs	(1,124)	—
Proceeds from sale of properties	1,375,000	—
Net cash used in investing activities	(10,541,269)	(2,222,947)
Cash flows from financing activities:		
Buyback of common shares	(2,856,350)	(663,944)
Exercise of stock options	54,250	—
Repayment of revolving line of credit	—	(2,900,000)
Net cash used in financing activities	(2,802,100)	(3,563,944)
Effect of currency rates on cash, cash equivalents and restricted cash	12,548	(115,306)
Increase (decrease) in cash, cash equivalents and restricted cash	(345,807)	4,403,801
Cash, cash equivalents and restricted cash, beginning of year	14,959,518	10,555,717
Cash, cash equivalents and restricted cash, end of year	$ 14,613,711	$ 14,959,518
Supplemental cash flow disclosures:		
Income taxes paid	$ 2,794,422	$ 4,130,493
Interest paid	$ 119,138	$ 136,833
Non-cash investing activities:		
Change in proved properties accrued in accounts payable and accrued liabilities	$ 1,464,965	$ (587,472)
Change in gathering system accrued in accounts payable and accrued liabilities	$ (40,782)	$ (48,961)
Asset retirement obligation asset additions and adjustments	$ 1,169,903	$ (135,900)

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. The Company is engaged in the acquisition, development, gathering and production of primarily natural gas reserves in the United States.

2. Basis of Preparation

The accounts are maintained and the consolidated financial statements have been prepared using the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). All amounts presented are in US$ unless otherwise indicated.

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, Dewey Energy GP, LLC, and Dewey Energy 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.

Reclassifications

Certain amounts reported in prior year's consolidated financial statements have been reclassified to conform to the current presentation with no effect on shareholders' equity or net income.

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, 2019 and December 31, 2018:

	Year ended December 31,	
	2019	2018
Cash and cash equivalents	$ 14,052,417	$ 14,401,257
Restricted cash included in other assets	561,294	558,261
Cash, cash equivalents and restricted cash in the statement of cash flows	$ 14,613,711	$ 14,959,518

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. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. 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, 2019 and 2018. There was no bad debt expense recognized for the years ended December 31, 2019 and 2018.

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 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 unamortized capitalized cost 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 unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic ASC 820, which considers estimated discounted future cash flows.

Gas Gathering System Properties

Epsilon accounts for its gas gathering system asset using the proportionate consolidation method of accounting.

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 described in Fair Value Measurement Topic ASC 820, 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.

We adopted Accounting Standards Codification ("ASC") topic 606 on January 1, 2019. The standard requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU replaced most existing revenue recognition guidance in GAAP when it became effective and was incorporated into GAAP as Accounting Standards Codification ("ASC") Topic 606. 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. The Company applied the guidance to the contracts in effect at January 1, 2019 and used the modified retrospective transition method. There was no material impact to our net income related to the adoption of this standard. Based on ASC 606, the Company adheres to the following revenue recognition policies and procedures.

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 3rd party sales transportation pipeline. The Company recognizes revenue proportionate to its entitled share of volumes sold. Currently, almost all 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 3rd party sales transmission point. Revenue is recognized over time as the services are provided.

Accounts Receivable and Other

Accounts receivable – Oil, natural gas liquid and natural gas receivables consist of amounts due from purchasers for commodity sales primarily from our revenue interest in the leases in Northwestern Pennsylvania. 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, accrued liabilities, and long-term debt.

Our financial instruments that are accounted for at fair value measurement 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, restricted cash, accounts receivable, accounts payable and accrued liabilities are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's revolving line of credit has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates.

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. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

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.

Derivative assets and liabilities are initially measured at fair value and then re-valued at each reporting period. Using this method, 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 obligation relates 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 obligation 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, 2019 and 2018, the cash and cash equivalents were primarily concentrated in two financial institutions, one in Canada and one in the US. The Company periodically assesses the financial condition of these institutions and believe that any possible credit risk is minimal.

Geographic Locations of Operations

Through December 31, 2019, our primary source of revenue originated 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. To this end, we have begun to acquire leases in the Anadarko basin and to expand our holdings in Pennsylvania.

Income Taxes

Income taxes are accounted for using the asset and liability approach. Under this approach, 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

The United States dollar is the functional 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 restricted stock to employees and directors of the Company. The fair value of the restricted stock is determined using the fair value of the Company's common stock on the date of 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

Agreements under which the Company makes payments to owners in return for the right to use an asset for a period are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership to third parties are recorded at inception as finance leases within property and equipment and debt. Assets acquired under capital leases are amortized over the estimated useful lives of the underlying assets. All other leases are accounted for as operating leases and the related lease payments are charged to expense as incurred.

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 guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Early adoption is permitted.

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 evaluating the impact of the adoption of ASU 2016-13 on January 1, 2023.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)" (ASU 2016-02), which significantly changes 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 will also be 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." ASU 2016-02 is effective for the Company for fiscal years beginning after December 15, 2020, and interim periods within fiscal years beginning after December 15, 2021. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. Epsilon is reviewing the provisions of ASU 2016-02 to determine the impact on its consolidated financial statements and related disclosures. Epsilon is evaluating the impact of the adoption of ASU 2016-02 on the financial statements.

4. Property and Equipment

The following table summarizes the Company's property and equipment at December 31, 2019 and 2018:

	December 31, 2019	December 31, 2018
Property and equipment:		
Oil and gas properties, successful efforts method		
Proved properties	$ 130,819,256	$ 118,851,574
Unproved properties	21,047,512	19,498,666
Accumulated depletion, depreciation, and amortization	(89,255,035)	(83,807,401)
Total oil and gas properties, net	62,611,733	54,542,839
Gathering system	41,445,225	41,040,847
Accumulated depletion, depreciation, and amortization	(29,961,690)	(28,137,573)
Total gathering system, net	11,483,535	12,903,274
Land	375,314	—
Buildings and other property and equipment, net	211,879	—
Total property and equipment, net	$ 74,682,461	$ 67,446,113

Property Acquisitions

During the years ended December 31, 2019 and 2018 the Company acquired additional acreage in the Anadarko Basin for $596,500 and $260,000, respectively. Included in additions to proved natural gas and oil properties for the year ended December 31, 2018 was an approximate $0.5 million cash call refund for wells previously drilled.

Property Sale

In June 2019, the Company completed the first part of a sale of undeveloped, stranded leases in Pennsylvania. At that time, the Company received $1.0 million. The sale was completed in July 2019 with a final payment of $0.4 million for a total of $1.4 million received for the stranded leases.

Property Impairment

At December 31, 2019 and 2018, the Company evaluated its proved and unproved natural gas and oil properties, and its gathering system assets for indicators of any potential impairment. As a result of these assessments, no impairment was required for the years ended December 31, 2019 and 2018.

5. Revolving Line of Credit

Effective July 30, 2013, Epsilon Energy USA Inc., a wholly owned subsidiary of the Company, executed a three-year senior secured revolving credit facility with a bank (''Credit Facility'') for a total commitment of up to $100 million. Upon each advance, interest is charged at the rate of LIBOR plus an ''applicable margin''. The applicable margin ranges from 2.75 - 3.75% and is based on the percent of the line of credit utilized.

The terms "Borrowing Base" and "Mortgaged Properties" include the Company's gathering system assets in addition to the natural gas and oil properties. The "Required Reserve Value" is the lesser of 90% of the recognized value of all proved natural gas and oil properties or 150% of the then current borrowing base.

On January 7, 2019, the maturity date of the Credit Facility was extended to March 1, 2022 and the borrowing base was increased from $13.5 million to $23 million. The borrowing base is subject to redetermination by the lenders based on, among other things, their evaluation of the Company's natural gas reserves. Additionally, the Company is required to maintain acceptable commodity hedging agreements covering at least 25% of projected production of natural gas for the succeeding calendar year, along with the 50% for the current calendar year.

On August 14, 2019 the borrowing base was reaffirmed at $23 million. Additionally, the commodity hedging requirements were updated. Currently, when the Company's utilization exceeds 25%, the Company must have in place acceptable commodity hedging agreements covering at least 75% of projected production for the first full twelve months after such occurrence and 50% of projected production of natural gas for the succeeding six months.

On February 11, 2020 the borrowing base was reaffirmed at $23 million and hedging requirements remained unchanged.

The lender under the Credit Facility has a first priority security interest in the tangible and intangible assets, including the gathering system, 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 based on income adjusted for interest, taxes and non-cash amounts.
- Current ratio, adjusted for line of credit amounts used and available and non-cash amounts, greater than 1.
- Leverage ratio less than 3.5 based on income adjusted for interest, taxes and non-cash amounts.

The Company was in compliance with the financial covenants of the Credit Facility as of December 31, 2019 and 2018 and we expect to be in compliance with the financial covenants for the next 12 months.

A commitment fee of 0.50% is assessed quarterly on the daily average unused borrowing base on the Credit Facility

	Balance at December 31, 2019	Balance at December 31, 2018	Current Borrowing Base	Interest Rate 3 mo.
Revolving line of credit	$ —	$ —	$ 23,000,000	LIBOR + 2.75% (1)

(1) At December 31, 2019, the interest rate was 4.65%.

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

Prior to moving the Company listing from the TSX to the NASDAQ, and prior to the purchase of the equity shares on the NASDAQ shown below, the Company purchased shares through a normal-course issuer bid ("NCIB") program with the TSX, which expired February 28, 2019. On the TSX, the Company repurchased and retired 57,100 shares of common stock through the year ended December 31, 2019. The repurchased stock had an average price of $4.26 per share. The average share price (converted to US$ using a rate of Cdn$1.33 to US$1) on the TSX from January 1, 2019 through the last day of trading on the TSX, March 15, 2019, was $4.22 (for the year ended December 31, 2018, $3.98).

Commencing on May 20, 2019, the Company entered into a share repurchase program on the NASDAQ conducted in accordance with Rule 10b-18 promulgated under the Securities Exchange Act of 1934. The Company is authorized to repurchase up to 1,367,762 of its outstanding common shares, representing 5% of the outstanding common shares of Epsilon as of May 20, 2019, for an aggregate purchase price of not more than $2.5 million. The program will end on May 19, 2020 unless the maximum amount of common shares is purchased before then or Epsilon provides earlier notice of termination.

Repurchases may be made at management's discretion from time to time through the facilities of the NASDAQ Global Market. The price paid for the common shares will be, subject to applicable securities laws, the prevailing market price of such common shares on the NASDAQ Global Market at the time of such purchase. The Company intends to fund the purchase out of available cash and does not expect to incur debt to fund the share repurchase program.

The following table contains information about our repurchase of equity securities during the year ended December 31, 2019:

	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
Beginning balance at May 20, 2019			—	1,367,762
May 2019	16,148	$ 4.17		
June 2019	221,041	$ 4.12		
July 2019	55,112	$ 3.90		
August 2019	56,432	$ 3.66		
September 2019	14,797	$ 3.79		
October 2019	42,307	$ 3.38		
November 2019	290,259	$ 3.41		
Total for the year ended December 31, 2019	696,096	$ 3.72	696,096	671,666

(c) Stock Options

The Company maintains a stock option plan for directors, officers, employees and consultants of the Company and its subsidiaries.

Through December 31, 2019, the Company had issued stock options covering 245,000 Common Shares at an overall average price of $5.27 per Common Share to directors, officers and employees of the Company and its subsidiaries. A maximum amount of 755,000 Common Shares are available for future option issuances.

The following table summarizes stock option activity for the years ended December 31, 2019 and 2018:

	Year ended December 31, 2019		Year ended December 31, 2018	
Exercise price in US$	Number of Options Outstanding	Weighted Average Exercise Price [(1)]	Number of Options Outstanding	Weighted Average Exercise Price [(1)]
Balance at beginning of period	290,750	$ 5.02	330,750	$ 5.14
Exercised	(25,000)	2.17	—	—
Expired/Forfeited	(20,750)	5.37	(40,000)	6.00
Balance at period-end	245,000	$ 5.27	290,750	$ 5.02
Exercisable at period-end	206,670	$ 5.32	210,249	$ 5.02

At December 31, 2019, the Company had unrecognized stock based compensation related to these options of $1,867 to be recognized over a weighted average period of 0.08 years (for the year ended December 31, 2018: $27,877 over 1.1 years). The aggregate intrinsic value at December 31, 2019 was nil (at December 31, 2018: $58,664).

During the year ended December 31, 2019, the Company awarded no stock options (During the year ended December 31, 2018: no stock options).

The following table summarizes information for stock options outstanding at December 31, 2019:

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, 2019				
$5.02	115,000	76,670	$ 201,630	4.08
$5.50	130,000	130,000	276,299	2.43
Total	245,000	206,670	$ 477,929	3.04

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, 2019 and 2018, was $25,203 and $83,328, respectively.

(d) Share Compensation Plan

A Share Compensation Plan (the "Plan") was adopted by the Board on April 13, 2017 and approved by the shareholders at the Annual General Meeting in April 2017. The Plan provides that designated participants may, as determined by the Board, be issued Common Shares in an amount up to 100% of the participant's compensation paid by the Company in consideration of the participant's service for the current year divided by the market price of the Common Shares on the NASDAQ at the date of issuance of the Common Shares in the current year.

In December 2019, 184,500 common shares of Restricted Stock were awarded to the Company's officers, employees, and board of directors (in December 2018, 174,500 shares). These shares vest over a three year period, with one-third of the 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 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. Stock compensation expense for the granted Restricted Stock is recognized over the vesting period. Stock compensation expense recognized during the years ended December 31, 2019 and 2018 was $485,257 and $246,904, respectively.

At December 31, 2019, the Company had unrecognized stock based compensation related to these shares of $1,641,295 to be recognized over a weighted average period of 1.12 years (for the year ended December 31, 2018: $1,767,975 over 1.42 years).

The following table summarizes Restricted Stock activity for the years ended December 31, 2019 and 2018:

	Year ended December 31, 2019		Year ended December 31, 2018	
	Number of Shares Outstanding	Weighted Average Remaining Life (years)	Number of Shares Outstanding	Weighted Average Remaining Life (years)
Balance non-vested Restricted Stock at beginning of period	282,833	2.56	162,500	1.87
Granted	184,500	3.00	174,500	3.00
Vested	(106,834)	—	(54,167)	—
Forfeited	(14,000)	2.64	—	—
Balance non-vested Restricted Stock at end of period	346,499	1.67	282,833	2.56

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.

Upon adoption, we did not make any changes to our revenue reporting based on ASC 606 (Note 3).

The following table details revenue for the years ended December 31, 2019 and 2018:

	Year Ended December 31, 2019	Year Ended December 31, 2018
Operating revenue		
Natural gas	$ 16,945,302	$ 19,031,422
Natural gas liquids	110,394	295,142
Oil and condensate	314,267	376,079
Gathering and compression fees	9,320,373	9,981,562
Total operating revenue	$ 26,690,336	$ 29,684,205

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers, and the related cash consideration are received within 30 days for natural gas, NGLs, oil, or condensate sold, and 60 days for gas gathering revenues. 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, NGLs, oil, 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. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of December 31, 2019 and 2018 were $2.4 million and $3.0 million, respectively.

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. The accounts receivable balances from the operator of the Auburn GGS within the accompanying balance sheets as of December 31, 2019 and 2018 were $1.9 million and nil, respectively. The receivable balance was nil at December 31, 2018 as the Company had previously been overpaid by the operator.

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 of Accumulated Other Comprehensive Income during the years ended December 31, 2019 and 2018 consisted of the following:

	Year Ended December 31, 2019	2018
Balance at beginning of period	$ 9,797,930	$ 9,913,236
Translation gain (loss) other	12,548	(115,306)
Balance at end of period	$ 9,810,478	$ 9,797,930

Substantially all of the accumulated other comprehensive income is related to the translation adjustment for the Canadian convertible debentures settled in 2017.

9. Income Taxes

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

	Year ended December 31, 2019	2018
Foreign	(307,286)	$ (665,924)
U.S.	12,782,774	8,070,409
	$ 12,475,488	$ 7,404,485

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 ended December 31, 2016 through December 31, 2019.

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

	Year ended December 31, 2019	2018
Current:		
Federal	$ 1,010,181	$ 1,742,898
State	355,122	(428,068)
Total current income tax expense	1,365,303	1,314,830
Deferred:		
Federal	1,527,937	(392,574)
State	884,249	(179,831)
Total deferred tax expense (benefit)	2,412,186	(572,405)
Income tax expense	$ 3,777,489	$ 742,425

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 2019 differs from the statutory rate primarily due to state taxes. In addition to state taxes, our effective tax rate for 2018 differs from the statutory rate primarily due to lapsed uncertain tax positions.

	Year Ended December 31, 2019	Effective Tax Rate	Year Ended December 31, 2018	Effective Tax Rate
Income tax provision computed at the statutory federal tax rate	$ 2,619,853	21.00 %	$ 1,554,942	21.00 %
Difference in Canadian and U.S. tax rate	(16,901)	(0.14)%	(30,633)	(0.41)%
Valuation allowance on Canadian loss	81,431	0.65 %	170,477	2.30 %
Return to provision adjustment	16,503	0.13 %	(179,120)	(2.42)%
State taxes	979,102	7.85 %	349,643	4.72 %
Miscellaneous other items	97,501	0.80 %	28,860	0.39 %
Change in uncertain tax position	—	— %	(1,151,744)	(15.55)%
Income tax expense	**$ 3,777,489**	**30.29 %**	**$ 742,425**	**10.03 %**

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.

As of December 31, 2019, we have no U.S. federal net operating loss carry-forwards and approximately $8.5 million of state net operating loss carry-forwards, which begin to expire after 2025. These loss carryforwards may reduce future taxable income, however, the extent of which may be limited due to any IRC Section 382 limitation.

Net deferred tax liabilities consisted of the following at December 31, 2019 and 2018:

	As at December 31, 2019	As at December 31, 2018
Deferred tax assets:		
State net operating loss carryforwards	$ 492,672	$ 465,496
Canadian net operating loss carryforwards	12,195,114	12,113,684
ARO	833,562	—
Unrealized Hedge/Other	71,524	91,646
Gross deferred tax assets	13,592,872	12,670,826
Valuation allowance	(12,195,114)	(12,113,684)
Total deferred tax assets	1,397,758	557,142
Deferred tax liabilities:		
Oil and gas property	(10,210,078)	(7,407,828)
Partnership	(3,016,277)	(3,138,592)
Unrealized Hedge/Other	(572,867)	—
Total deferred tax liabilities	(13,799,222)	(10,546,420)
Net deferred tax liability	$ (12,401,464)	$ (9,989,278)

We have recorded a valuation allowance against the Canadian net operating losses as we do feel that it is more likely than not that they will not be utilized as the Company does not have any revenue producing activities in Canada.

We are subject to taxation in the United States and various state jurisdictions. As of December 31, 2019 and 2018, the Company had no gross liability for income taxes associated with 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, 2019 and 2018.

10. Commitments and Contingencies

The Company's future minimum lease commitments as of December 31, 2019 are summarized in the following table:

Year ended December 31,	Payments
2020	90,553
2021	103,693
2022	107,419
2023	18,007
	$ 319,672

The Company enters into commitments for capital expenditures in advance of the expenditures being made. As of December 31, 2019, we had commitments of $2.0 million for capital expenditures.

Litigation

The Company is not currently involved in any litigation. Management is of the opinion that the potential for litigation is remote.

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,	
	2019	2018
Net income available to shareholders	$ 8,697,999	$ 6,662,060

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

	Year ended December 31,	
	2019	2018
Basic weighted-average number of shares outstanding	27,129,430	27,462,788
Dilutive stock options	—	11,337
Diluted weighted average shares outstanding	27,129,430	27,474,125

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

	Year ended December 31,	
	2019	2018
Anti-dilutive options	206,670	279,413
Anti-dilutive unvested restricted shares	346,499	282,833
Total Anti-dilutive shares	553,169	562,246

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 at, and for the years ended December 31, 2019 and 2018 is as follows:

	Upstream	Gas Gathering	Corporate	Elimination	Consolidated
As at and for the year ended December 31, 2019					
Operating revenue					
Natural gas	$ 16,945,302	$ —	$ —	$ —	$ 16,945,302
Natural gas liquids	110,394	—	—	—	110,394
Oil and condensate	314,267	—	—	—	314,267
Gathering and compression fees	—	10,517,439	—	(1,197,066)	9,320,373
Total operating revenue	**$ 17,369,963** (1)	**$ 10,517,439**	**$ —**	**$ (1,197,066)**	**26,690,336**
Net earnings for the period	**$ 5,151,434**	**$ 6,158,670**	**$ (2,612,105)**(3)	**—**	**$ 8,697,999**
Operating costs	6,571,394	2,534,475	—	(1,197,066)	7,908,803
Development geological and geophysical expenses	83,748	—	—	—	83,748
Depletion, deprec., amortization and accretion	5,563,387	1,824,294	—	—	7,387,681
Segment assets	**$ 83,056,034**	**$ 14,430,680**	**$ 182,489**	**—**	**$ 97,669,203**
Capital expenditures(2)	13,014,051	325,277	—	—	13,339,328
Proved properties	41,564,221	—	—	—	41,564,221
Unproved properties	21,047,512	—	—	—	21,047,512
Gathering system	—	11,483,535	—	—	11,483,535
Other property and equipment	587,193	—	—	—	587,193
As at and for the year ended December 31, 2018					
Operating revenue					
Natural gas	$ 19,031,422	$ —	$ —	$ —	$ 19,031,422
Natural gas liquids	295,142	—	—	—	295,142
Oil and condensate	376,079	—	—	—	376,079
Gathering and compression fees	—	11,087,507	—	(1,105,945)	9,981,562
Total operating revenue	**$ 19,702,643** (1)	**$ 11,087,507**	**$ —**	**$ (1,105,945)**	**29,684,205**
Net earnings for the period	**$ 7,742,587**	**$ 6,814,188**	**$ (7,894,715)**(3)	**$ —**	**$ 6,662,060**
Operating costs	6,665,856	2,385,766	—	(1,105,945)	7,945,677
Depletion, deprec., amortization and accretion	5,294,200	1,887,553	—	—	7,181,753
Segment assets	**$ 71,350,546**	**$ 15,440,047**	**$ 1,107,116**	**$ —**	**$ 87,897,709**
Capital expenditures(2)	2,472,919	197,321	—	—	2,670,240
Proved properties	35,044,173	—	—	—	35,044,173
Unproved properties	19,498,666	—	—	—	19,498,666
Gathering system	—	12,903,274	—	—	12,903,274

(1) Segment operating revenue represents revenues generated from the operations of the segment. Inter-segment sales during the years ended December 31, 2019 and 2018 have been eliminated upon consolidation. For

the year ended December 31, 2019, Epsilon sold natural gas to 29 unique customers. The two customers over 10% comprised 47% and 27% of total revenue. For the year ended December 31, 2018, Epsilon sold natural gas to 28 unique customers. The two customers over 10% comprised 46% and 21% of 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.

(3) Segment reporting for net earnings for the period does not include non-monetary compensation, general and administrative expense, interest income, interest expense or income tax amounts as they are managed on a group basis and are instead included in the corporate column for reconciliation purposes. Additionally, gains & (losses) from commodity hedging contracts are also included in the corporate column for reconciliation purposes.

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 2019, Epsilon recognized gains on financial commodity derivative contracts of $4,246,057. This amount included cash received on settlements of these contracts of $1,949,232. For 2018, Epsilon recognized losses on financial commodity derivative contracts of $1,938,465. This amount included cash paid on settlements of these contracts of $1,381,898.

Commodity Derivative Contracts

Epsilon's outstanding natural gas price swap contracts as of December 31, 2019 consisted of:

Derivative Type	Volume (Mmbtu)	Weighted Average Price ($/MMbtu) Swaps	Basis Differential	Fair Value December 31, 2019
2020				
Fixed price swap	4,637,500	$ 2.71	$ —	2,001,496
Basis swap	4,637,500	$ —	$ (0.43)	(1,694)
				$ 1,999,802

As of December 31, 2019 and 2018, all of the Company's economic derivative hedge positions were with large financial institutions, which are not known to the Company to be in default on their derivative positions. The Company is exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate non-performance by such counterparties. None of the Company's derivative instruments contains credit-risk related contingent features. Derivatives are net on the balance sheet as they are subject to the right to offset the liabilities with the assets.

	Fair Value of Derivative Assets December 31, 2019	December 31, 2018
Current		
Basis swap	$ 162,844	$ 76,075
Fixed price swap	2,001,496	125,790
	$ 2,164,340	$ 201,865

	Fair Value of Derivative Liabilities December 31, 2019	December 31, 2018
Current		
Basis swap	$ (164,538)	$ (337,438)
Fixed price swap	—	(161,450)
	$ (164,538)	$ (498,888)
Net Fair Value of Derivatives	$ 1,999,802	$ (297,023)

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

	Year ended December 31, 2019	2018
Fair value of asset (liability), beginning of year	$ (297,023)	$ 259,544
Gains (losses) on derivative contracts included in earnings	4,246,057	(1,938,465)
Settlement of commodity derivative contracts	(1,949,232)	1,381,898
Fair value of asset (liability), end of year	$ 1,999,802	$ (297,023)

14. Asset Retirement Obligations

Asset retirement obligations were 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 $2.9 million as at December 31, 2019 ($1.6 million at December 31, 2018) based on a total net future undiscounted liability of approximately $8.9 million ($21.5 million at December 31, 2018). Each year we review, and to the extent necessary, revise our asset retirement obligation estimates. During 2019 and 2018, we reviewed the actual abandonment costs with previous estimates. As a result, estimates of abandonment costs remained constant in 2019, but were updated at the end of 2018. Our overall liability increased due to the addition of new wells in both Pennsylvania and Oklahoma. From 2018 to 2019 our undiscounted liability decreased due to a decrease in the economic life of several of the wells in Pennsylvania. The life of the wells decreased due to the decrease in natural gas prices which caused the wells to be economically profitable for a shorter period of time. Due to the decrease in the life of the wells, there were fewer years of inflation affecting the plug and abandonment costs thereby lowering the estimate from December 31, 2018 to December 31, 2019.This was offset by the drilling of new wells which added to the liability. Even though the undiscounted liability decreased, the discounted liability shown below increased due to the effect of the discounting over time. The liability is spread over a shorter period so the ARO balance has increased at December 31, 2019 over the balance at December 31, 2018.

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

	Year Ended December 31, 2019	Year ended December 31, 2018
Balance beginning of period	$ 1,625,154	$ 1,646,601
Liabilities from drilling of new wells	16,163	1,590
Change in estimates	1,153,740	(137,490)
Accretion	114,798	114,453
Balance end of period	$ 2,909,855	$ 1,625,154

15. Consolidation of Common Shares

To meet NASDAQ listing standards, the shareholders of the Company on December 19, 2018 approved a Consolidation of the issued and outstanding common shares on the basis of one (1) new common share for up to every existing two (2) common shares issued and outstanding immediately prior to the Consolidation. The common shares commenced trading on a post-Consolidation basis on the TSX on December 24, 2018. All share amounts and per share data are presented in these statements on a post-Consolidation basis.

NATURAL GAS AND OIL PRODUCING ACTIVITIES

The following disclosures are made in accordance with Financial Accounting Standards Board Accounting Standards Update No. 2010-03 ‘‘Natural gas and oil Reserve Estimates and Disclosures’’ and the United States Securities and Exchange Commission’s (SEC) final rule on ‘‘Modernization of Natural gas and oil Reporting.’’

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, 2019. 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, 2019 and 2018 and changes for each of the two years in the period ended December 31, 2019. Net proved reserves at December 31 are estimated by the Company’s independent petroleum engineers, DeGolyer and MacNaughton.

NET PROVED RESERVE SUMMARY

All reserves located in United States	Natural Gas (MMcf)	Oil (MBbl)	Total (MMcfe)
Net proved reserves at December 31, 2017	215,588	37	215,812
Revisions of previous estimates[1][2][4]	(89,558)	(1)	(89,564)
Improved recoveries[3]	717	—	717
Production	(7,631)	(6)	(7,665)
Net proved reserves at December 31, 2018	119,116	31	119,299
Revisions of previous estimates[1][2][4]	(3,356)	91	(1,884)
Improved recoveries[3]	16,210	—	16,210
Production	(7,808)	(6)	(7,844)
Net proved reserves at December 31, 2019	124,161	116	125,780
Proved developed reserves:			
At December 31, 2017	60,571	37	60,795
At December 31, 2018	50,698	31	50,881
At December 31, 2019	67,158	35	67,367
Proved undeveloped reserves:			
At December 31, 2017	155,017	—	155,017
At December 31, 2018	68,418	—	68,418
At December 31, 2019	57,003	81	58,413

(1) Revisions of previous estimates in the proved producing category are primarily attributable to an increase in the natural gas price.

(2) Revisions of previous estimates in the proved undeveloped category is attributable to undeveloped well locations being removed due to lease expiration and revised spacing assumptions.

(3) Improved recoveries in the proved producing category are primarily attributable to revisions to the expected production curves from the previous year.

(4) During 2019, 19 MMcf were added to proved producing from the shut-in category. During 2018, 934 MMcf were transferred from net proved undeveloped, 306 MMcf moved to net proved developed producing and 628 MMcf moved to net proved developed non-producing.

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 producing activities at December 31, 2019 and 2018:

	Year ended December 31, 2019	Year ended December 31, 2018
Proved properties	$ 130,819,256	$ 118,851,574
Unproved properties	21,047,512	19,498,666
Gathering system properties	41,445,225	41,040,847
Total Oil & Gas Properties	193,311,993	179,391,087
Accumulated depreciation, depletion and amortization	(119,216,725)	(111,944,974)
Net capitalized costs	$ 74,095,268	$ 67,446,113

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, 2019	Year ended December 31, 2018
Oil and Natural Gas Activities:		
Proved acquisition costs	$ —	$ 4,992
Unproved acquisition costs	1,548,845	2,047,114
Development costs[(1)]	11,967,683	321,890
Total costs incurred for oil and natural gas activities	13,516,528	2,373,996
Gathering System development costs	404,378	160,344
Total costs incurred	$ 13,920,906	$ 2,534,340

[(1)] Development costs for 2018 include a $0.5 million cash call refund for wells previously drilled.

Results of Operations for Natural gas and oil Producing Activities

The following table sets forth results of operations for gas producing activities for the years ended December 31, 2019 and 2018:

	Year ended December 31, 2019	Year ended December 31, 2018
Oil and gas producing activities:		
Gas sales	$ 16,945,302	$ 19,031,422
Oil and other liquid sales	424,661	671,221
Total revenues	17,369,963	19,702,643
Lease operating costs	(6,571,394)	(6,665,856)
Depreciation, depletion, amortization, and accretion	(7,387,681)	(5,294,200)
Total costs	(13,959,075)	(11,960,056)
Results of operations from oil and gas producing activities	$ 3,410,888	$ 7,742,587

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 gas and oil Topic of the ASC and based on natural gas reserves and production volumes estimated by the reserve engineers of 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 2019 and 2018. 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, 2019 and 2018.

	Year ended December 31,	
	2019	**2018**
Future cash inflows	$ 273,520,165	$ 314,768,187
Future production costs	(96,030,523)	(113,557,103)
Future development costs[(1)]	(45,921,253)	(35,324,796)
Future income taxes[(2)]	(33,809,160)	(45,050,385)
10% annual discount for estimated timing of cash flows	(48,142,188)	(61,761,091)
Standardized measure of discounted future net cash flows	$ 49,617,041	$ 59,074,812

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

(2) Future income taxes for 2019 and 2018 were estimated using a combined federal and state statutory tax rate of approximately 27.6%.

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, 2019 and 2018:

	Year ended December 31,	
	2019	2018
Beginning balance	$ 59,074,811	$ 49,715,557
Revenue less production and other costs	(10,803,630)	(13,042,411)
Changes in price, net of production costs	(22,711,161)	44,764,807
Development costs incurred	10,462,724	512,314
Net changes in future development costs	(12,687,334)	50,335,213
Revisions of previous quantity estimates	11,039,025	(75,979,298)
Accretion of discount	8,198,969	7,382,905
Net change in income taxes	4,764,315	(3,192,058)
Timing differences and other technical revisions	2,279,322	(1,422,217)
Ending balance	$ 49,617,041	$ 59,074,812

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, 2019, 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 Securities Exchange Act of 1934. 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 (2013 Framework). Based on our evaluation under the 2013 Framework, we have concluded that the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019.

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 Securities and Exchange Commission 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

No changes in our internal control over financial reporting occurred during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Directors and Executive Officers. The names, ages, business experience (for at least the past five years) and positions of our directors and executive officers as of December 31, 2019, 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.

Director or Executive Officer	Age	Position with us
Mike Raleigh	63	Chief Executive Officer and Director
Lane Bond	61	Chief Financial Officer
Henry Clanton	57	Chief Operating Officer
John Lovoi	58	Chairman of the Board and Director
Matt Dougherty	38	Director
Ryan Roebuck	34	Director
Jacob Roorda	62	Director
Tracy Stephens	59	Director
Stephen Finlayson	65	Director

Biographies of Corporate Directors and Executive Officers.

Michael Raleigh. Mr. Raleigh has served as chief executive officer and a director for Epsilon Energy Ltd. since July 2013. Before becoming chief executive officer at Epsilon Energy Ltd., he acted in various positions in the global natural gas and oil business for 35 years, primarily holding positions in the areas of reservoir development strategy, property valuations, completions and production. He has also been managing investments with Domain Energy Advisors since January 2005. Mr. Raleigh has been a member of the board of directors of Roan Resources, Inc., an Anadarko Basin-focused exploration and production company, since September 2019. He has also been managing investments with Domain Energy Advisors since January 2005. We believe that Mr. Raleigh is qualified to serve as a member of our board of directors as a result of his background in engineering, including reserve, acquisitions and valuation engineering, and his experience in the development and appraisal of natural gas and oil fields. Mr. Raleigh received a Bachelor of Science degree in Chemical Engineering from Queens University in Canada and received his Master of Business Administration degree from the University of Colorado.

B. Lane Bond. Mr. Bond has served as our chief financial officer since January 2012. He has served as the chief financial officer of Epsilon Energy USA and Epsilon Energy Midstream since January 2012. He has also been serving as the chief financial officer of Dewey Energy Holdings and Dewey Energy GP since March 2017. Mr. Bond's financial career spans over 30 years with extensive management and natural gas and oil experience domestically and internationally. Mr. Bond holds a Master of Business Administration from the University of Tulsa and a Bachelor of Science in Accounting from the University of Arkansas.

Henry N. Clanton. Mr. Clanton joined the Company as its Chief Operating Officer in 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, and a Director of Roan Resources, Inc., an Anadarko Basin-focused exploration and production company. 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.

Matthew Dougherty. Mr. Dougherty has been a director since July 2013 and serves as the chair of the Compensation, Nominating and Governing Committee. He has been the Managing Director of Advisory Research, Inc., an investment management firm since June 2003, where he oversees the firm's investments in oil and natural gas producers. He has served as the Portfolio Manager of the Advisory Research Energy Fund, LP since 2005. We believe that Mr. Dougherty is qualified to serve as a member of our board of directors because of his background in natural gas and oil and finance industries.

Ryan Roebuck. Mr. Roebuck has been a director since July 2011. He has also been serving as the chair of our Audit Committee, a member of our Compensation, Nominating and Governance Committee since July 2011, and a member of our Conflicts Committee since February 2018.Mr. Roebuck is currently the Principal of RR ONE LTD. an investment holding company located in Toronto, Canada. Prior to this position, Mr. Roebuck was an investment manager for a leading Canadian Venture Capital Firm where he was a founding investor and director of the Cronos Group. Mr. Roebuck began his career as a top-rated equity research analyst focused on North American special situations. We believe that Mr. Roebuck is qualified to serve as a member of our board of directors as a result of his background in the investment banking industry and as an investment manager.

Jacob Roorda. Mr. Roorda has been a director 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 is the managing director and chief executive officer of Windward Capital Limited, a private company, serving from October 2011 to January 2015, and again since July 2018. He was the Executive Vice President of Todd Energy International Ltd. from November 2016 to July 2018, and the Chief Executive Officer of Todd Energy Canada Ltd. from January 2015 to November 2016. Mr. Roorda currently serves on the Audit, Compensation, and Reserves Committee of Petroshale Inc. During the last five years, he also served on the boards of Wolf Minerals Limited and Northcliff Resources Ltd. None of these positions are, or have ever been, with companies affiliated with the Company. Mr. Roorda has also served on the board of Todd Energy Canada Ltd. 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. Mr. Finlayson is the founder and, since 2003, Executive Chairman of Applied Manufacturing Technologies, an independent international consulting and project services company supporting operating companies in the downstream refining and chemicals industries. We believe that Mr. Finlayson is qualified to serve as a member of our board of directors as a result of his extensive experience in the natural gas and oil industry, including advanced control solutions in natural gas and oil production.

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 11.25% of our common shares and Chairman of the Board. Mr. Raleigh is our Chief Executive Officer and a member of JVL Advisors, LLC.

The Board held six meetings during 2019 and seven meetings during 2018. 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 consists of Ryan Roebuck (Chairman), Jacob Roorda, and Stephen Finlayson. 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 comprises Matthew Dougherty (chairman), Tracy Stephens and Ryan Roebuck, all three members of this committee are independent directors. Before July 2013, we had separate compensation committee and nominating and corporate governance committee. Both committees' mandates were approved by the Board on December 10, 2009. In July 2013, the Board consolidated the functions of the two committees for efficiency purposes.

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 comprises Jacob Roorda (Committee Chairman), Tracy Stephens and Ryan Roebuck, all of whom 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., 16945 Northchase Drive, Suite 1610, Houston, Texas 77060, 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

The named executive officers, excluding Michael Raleigh, have executed employment contracts with us. Mr. Henry Clanton's employment contract calls for a base pay of $250,000 per year. Mr. B. Lane Bond's employment contract calls for a base pay of $200,000 per year and contains provisions for severance payments equal to six months of current annual salary in the event that a change of control occurred.

Mr. Michael Raleigh does not take a salary for his efforts with us and does not have an employment contract.

ITEM 11. EXECUTIVE COMPENSATION.

Summary Compensation Table

In April 2017 the Board amended and restated the 2007 Plan, which is currently called the Amended and Restated 2017 Stock Option Plan (the '2017 Plan'). In addition, in 2017, the Board adopted, and the Company's shareholders approved, the Share Compensation Plan. 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, 2019 and 2018. Compensation amounts in the following table are in U.S. dollars unless stated otherwise. All share balances and income (loss) per share amounts are presented on a post-Consolidation basis (see note 16 to the consolidated financial statements)

Name and principal position	Year	Salary	Bonuses and Director Fees	Share-based Awards	Option-based Awards	Non-equity incentive plan compensation: Annual Incentive Plans	Non-equity incentive plan compensation: Long-term Incentive Plans	Pension Value	Total Compensation
Michael Raleigh, CEO [1]	2019	$ —	$ —	$ 189,750	$ —	$ —	$ —	$ —	$ 189,750
	2018	$ —	$ —	$ 280,706	$ —	$ —	$ —	$ —	$ 280,706
Henry Clanton, COO [2]	2019	$ 250,000	$ 75,000	$ 57,750	$ —	$ —	$ —	$ —	$ 382,750
	2018	$ 250,000	$ —	$ 78,598	$ —	$ —	$ —	$ —	$ 328,598
B. Lane Bond, CFO [3]	2019	$ 200,000	$ 62,000	$ 41,250	$ —	$ —	$ —	$ —	$ 303,250
	2018	$ 200,000	$ 70,000	$ 56,141	$ —	$ —	$ —	$ —	$ 326,141

(1) Mr. Raleigh is currently working without a salary from us; however, he was granted the following equity award in 2019 and 2018.

2019—Share award of 57,500 common shares under the Share Compensation Plan valued at $3.30 per share, market price on the grant date, December 31, 2019, which vest evenly over a three year period. Vested shares will be awarded on the anniversary date for each of the next three years, so long as Mr. Raleigh is still employed.

2018— Share award of 62,500 common shares under the Share Compensation Plan valued at $4.49 per share, market price on the grant date, December 31, 2018, which vest evenly over a three year period. Vested shares will be awarded on the anniversary date for each of the next three years, so long as Mr. Raleigh is still employed.

(2) Mr. Henry Clanton was hired as our chief operating officer in January 2018 with a base salary of US$250,000.

2019— Share award of 17,500 common shares under the Share Compensation Plan valued at $3.30 per share, market price on the grant date, December 31, 2019, which vest evenly over a three year period. Vested shares will be awarded on the anniversary date for each of the next three years, so long as Mr. Clanton is still employed.

2018— Share award of 17,500 common shares under the Share Compensation Plan valued at $4.49 per share, market price on the grant date, December 31, 2018, which vest evenly over a three year period. Vested shares will be awarded on the anniversary date for each of the next three years, so long as Mr. Clanton is still employed.

(3) Mr. Bond's current base salary is $200,000. The dollar amounts in column (e) reflect values derived from using the Trinomial Hull White option pricing to value option-based awards. A summary of the options granted by year follows:

2019— Share award of 12,500 common shares under the Share Compensation Plan valued at $3.30 per share, market price on the grant date, December 31, 2019, which vest evenly over a three year period. Vested shares will be awarded on the anniversary date for each of the next three years, so long as Mr. Bond is still employed.

2018— Share award of 12,500 common shares under the Share Compensation Plan valued at $4.49 per share, market price on the grant date, December 31, 2018, which vest evenly over a three year period. Vested shares will be awarded on the anniversary date for each of the next three years, so long as Mr. Bond is still employed.

Description of the 2017 Plan and the Share Compensation Plan.

Amended and Restated 2017 Stock Option Plan

The 2017 Plan was approved by the Board and shareholders in April 2017 as a restatement of our Amended and Restated 2010 Stock Option Plan.

The 2017 Plan is administered by the Board, a committee of the Board or one or more officers delegated authority by the Board to administer the 2017 Plan. The Board has the authority in its discretion to interpret the 2017 Plan. The Board determines to whom options are granted, the numbers of shares subject to options and all other terms and conditions of the options.

The maximum number common shares that may be issued under the 2017 Plan is 1,000,000. As of December 31, 2019, options for 245,000 common shares were outstanding under the 2017 Plan.

If options granted under the Plan expire or terminate for any reason without having been exercised, the shares subject to such options are again available for grant under the 2017 Plan. Options granted under the 2017 Plan are not transferable or assignable other than by will or other testamentary instrument or the laws of succession.

The exercise price of options granted under the 2017 Plan may not be less than the closing price of the common shares on the NASDAQ on the last trading day preceding the day on which the option is granted.

Each option granted under the 2017 Plan expires on the date specified by the applicable option agreement (not later than ten years following grant), subject to earlier termination as provided below.

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, the Board may determine that all unvested options will vest and be eligible for exercise within a period determined by the directors preceding the change of control. Options not exercised within this period will terminate.

If an optionee resigns from the Company or is terminated by the Company (with or without cause), or a consultant optionee's contract with the Company expires, such optionee's unvested options will immediately terminate and, subject to the option expiry date, the optionee's vested options may be exercised for a period of 30 days.

If an optionee becomes entitled to long-term disability payments pursuant to the Company's disability insurance program (or if not a participant in such program, would have been entitled to such payments if the optionee had been a participant in such program), all of the unvested options held by the optionee will vest on the day immediately preceding the day on which the optionee becomes entitled to long-term disability payments and the optionee will have the right, for a period of 180 days thereafter, to exercise all of the options.

If an optionee retires pursuant to a retirement policy approved by the Board, all of the unvested options held by the optionee will vest on the day immediately preceding the date of such optionee's retirement, and the optionee will have the right, for a period of 60 days thereafter, to exercise all of the options.

If an optionee dies, all of the unvested options held by the optionee will vest on the day immediately preceding the date of such optionee's death, and the estate of the deceased optionee will have the right, for a period of 180 days thereafter to exercise the deceased optionee's option.

Should the term of an option expire when the optionee cannot exercise the option pursuant to a Company insider trading policy in effect at that time (a ''Blackout Period'') or within nine business days following the expiration of a Blackout Period, option expiration date is automatically extended until the tenth business day after the end of the Blackout Period. The ten-business-day period may not be extended by the Board.

Share Compensation Plan

The Share Compensation Plan was adopted by the Board on April 13, 2017 and approved by the shareholders on May 24, 2017.

The Share Compensation Plan provides that up to a total of 1,000,000 common shares are authorized for issuance. As of December 31, 2019, a total of 346,499 common shares have been issued and are unvested under the Share Compensation Plan.

Under the Share Compensation Plan, the Board designates participants from among our directors, officers, key employees and consultants and, on the day or days of each fiscal year determined by the Board, awards to each participant common shares in an amount up to 100% of the participant's compensation for service during the current year divided by the market price of the Common Shares on the NASDAQ at the date of issuance. Upon any participant ceasing to be our director, officer, employee or consultant for any reason, such participant's right to be issued common shares pursuant to the Share Compensation Plan terminates immediately.

The Board may, in its sole discretion, impose restrictions on any common shares issued pursuant to the Share Compensation Plan. These restrictions may include, but are not limited to, vesting periods and trading restrictions for a period of time, as determined by the Board, from the date of issuance.

The Share Compensation Plan provides that the Board may make certain amendments to the Share Compensation Plan without the approval of our shareholders or any participant of the Share Compensation Plan in order to conform to applicable law or regulation or the requirements of the NASDAQ. In addition, the Board may terminate the Share Compensation Plan at any time, subject to applicable law or regulations and the approval of any regulatory authority having jurisdiction, and the approval of our shareholders if required by such regulatory authority.

Incentive Plan Awards for Named Executive Officers

Outstanding Share-Based Awards and Option-Based Awards as of December 31, 2019 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**
Michael Raleigh	50,000	$ 5.50	06/05/22	$ —	140,832	$ 464,746	$ 206,250
Henry Clanton	30,000	$ 5.02	01/30/24	$ —	29,167	$ 96,251	$ 19,250
B. Lane Bond	22,500	$ 5.50	06/05/22	$ —	20,833	$ 68,749	$ 13,750
B. Lane Bond	27,500	$ 5.02	01/30/24	$ —			

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, 2019 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**
Michael Raleigh	$ —	$ 206,250	$ N/A
Henry Clanton	$ —	$ 19,250	$ N/A
B. Lane Bond	$ —	$ 13,750	$ N/A

We have adopted the 2017 Plan as an incentive-based stock option award plan applicable to all named executive officers and employees.

Termination and Change of Control Benefits

All of our named executive officers, except Mr. Michael Raleigh, have entered into employment contracts with us.

Mr. B. Lane Bond's employment contract calls for a base pay of US$200,000 per year and contains provisions for severance payments equal to six months of current annual salary amount in the event of a change of control.

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

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, 2019 by our independent directors who are not named executive officers:

Name	Fees Earned (Cdn$)	Share-Based Awards (US$)	Option-Based	Non-Equity Incentive Plan Compensation	Pension Value	All Other Compensation	Total
John Lovoi*	$ —	$ 39,600	$ —	$ —	$ —	$ —	$ 39,600
Michael Raleigh*	$ —	$ 189,750	$ —	$ —	$ —	$ —	$ 189,750
Matthew Dougherty*	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Ryan Roebuck	$ 40,000	$ 39,600	$ —	$ —	$ —	$ —	$ 79,600
Jacob Roorda	$ 40,000	$ 39,600	$ —	$ —	$ —	$ —	$ 79,600
Tracy Stephens	$ 40,000	$ 39,600	$ —	$ —	$ —	$ —	$ 79,600
Stephen Finlayson	$ 24,516	$ 39,600	$ —	$ —	$ —	$ —	$ 64,116
Adrian Montgomery	$ 15,484	$ —	$ —	$ —	$ —	$ —	$ 15,484

* The two directors who are not independent, Messrs. Lovoi and Raleigh, choose not to receive payment for their service as board members. Mr. Dougherty also has chosen not to receive payment for his service.

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, independent board member compensation is fixed at an annual fee of Cdn$40,000, paid semi-annually in July and January.

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, 2019 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	10,000	$ 5.50	6/5/2022	$ —	20,500	$ 67,650	$ 18,150
Ryan Roebuck	10,000	$ 5.50	6/5/2022	$ —	20,500	$ 67,650	$ 18,150
Jacob Roorda	12,500	$ 6.70	1/30/2024	$ —	20,500	$ 67,650	$ 18,150
Tracy Stephens	—	$ —		$ —	20,500	$ 67,650	$ 18,150
Stephen Finlayson	—	$ —		$ —	12,000	$ 39,600	$ —

The values of incentive plan awards that were vested or earned during the year ended December 31, 2019 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	$ —	$ 18,150	$ N/A
Ryan Roebuck	$ —	$ 18,150	$ N/A
Jacob Roorda	$ —	$ 18,150	$ N/A
Tracy Stephens	$ —	$ 18,150	$ 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 $300,000 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 17, 2020, 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., 16945 Northchase Drive, Suite 1610, Houston, Texas 77060.

Name of Beneficial Owner	Number of Common Shares	Percentage of Common Shares Owned
5% Stockholders		
Advisory Research, Inc.(1)	3,168,133	11.83 %
JVL Advisors, LLC (2)	2,998,415	11.19 %
Oakview Capital Management, L.P.(3)	2,245,976	8.38 %
azValor Asset Management SGIIC SA (4)	3,527,817	13.17 %
Solas Capital Management LLC (5)	2,571,397	9.60 %
Named Executive Officers and Directors		
Matthew Dougherty (6)	97,650	*
Jacob Roorda (7)	88,400	*
Bruce Lane Bond (8)	135,167	*
John Lovoi (9)	3,016,415	11.25 %
Ryan Roebuck (10)	75,025	*
Tracy Stephens (11)	12,400	*
Stephen Finlayson (12)	—	*
Henry Clanton (13)	35,833	*
Michael Raleigh (14)	154,167	*
All executive officers and directors as a group (9 persons) (15)	3,615,057	13.41 %

* Indicates beneficial ownership of less than 1% of outstanding shares.

(1) The address of Advisory Research, Inc., or ARI, is 180 North Stetson Avenue, Suite 5500, Chicago, Illinois 60601. Advisory Research, Inc. ("ARI") is the general partner of Advisory Research Energy Fund, L.P., the direct beneficial holder of the common shares, as reported on a Schedule 13G filed with the SEC on February 18, 2020.

(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 Oakview Capital Management, L.P. is 3879 Maple Avenue, Suite 300, Dallas, Texas 75219. Pursuant to a Schedule 13G filed on February 14, 2020 jointly by and on behalf of each of Oakview Capital Management, L.P. ("Oakview Capital Management"), Oakview Value Fund, LP ("Oakview Value Fund"), Oakview Value Fund GP, LP ("Oakview GP"), Oakview Investments, LLC ("Oakview Investments"), Patrick Malone and Corey Henegar, Oakview Capital Management is the investment manager of, and may be deemed to indirectly beneficially own securities owned by Oakview Value Fund. Oakview GP is the general partner of, and may be deemed to indirectly beneficially own securities owned by Oakview Value Fund. Oakview Capital Management is the investment adviser to various separate managed accounts (collectively, the "Managed Accounts") and may be deemed to indirectly beneficially own securities owned by the Managed Accounts. Oakview Investments is the general partner of, and may be deemed to indirectly beneficially own, securities

owned by Oakview Capital Management. Mr. Malone and Mr. Henegar are the members of, and may be deemed to indirectly beneficially own securities owned by, Oakview Investments. Oakview Value Fund and the Managed Accounts are the record and direct beneficial owner of these securities. Oakview Value Fund and Oakview GP disclaim beneficial ownership of the securities held by the Managed Accounts.

(4) The address of azValor Asset Management SGIIC SA, or azValor, is Paseo de la Castellana 10, 3rd, Madrid, 28046, Spain. Alvaro Guzmàn de Làzaro, Chief Investment Officer at azValor, exercises the voting and dispositive power with respect to the common shares held by azValor.

(5) 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 February 14, 2020.

(6) Includes 97,650 shares held by Mr. Dougherty individually. Mr. Dougherty is a member of our board of directors.

(7) 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 $5.02) of options exercisable within 60 days of March 18, 2020.

(8) Includes 50,000 shares issuable upon the exercise (at exercise price of $5.02-$5.50) of options exercisable within 60 days of March 18, 2020. Mr. Bond is our chief financial officer.

(9) Includes the shares held by JVL. Includes 10,000 shares issuable upon the exercise (at exercise price of $5.50) of options held by Mr. Lovoi and exercisable within 60 days of March 18, 2020. Mr. Lovoi is the chairman of our board of directors.

(10) Includes 10,000 shares issuable upon the exercise (at exercise price of $5.50) of options exercisable within 60 days of March 18, 2020. Mr. Roebuck is a member of our board of directors.

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

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

(13) Includes 30,000 shares issuable upon the exercise (at exercise price of $5.02) of options exercisable within 60 days of March 18, 2020. Mr. Clanton is our chief operating officer.

(14) Includes 50,000 shares issuable upon the exercise (at exercise price of $5.50) of options exercisable within 60 days of March 18, 2020. Mr. Raleigh is our chief executive officer and a member of our board of directors.

(15) Includes 162,500 shares issuable upon the exercise (at exercise price of $5.02-$5.50) of options exercisable within 60 days of March 18, 2020.

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 2015, 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. Matthew Dougherty, Jacob Roorda, Tracy Stephens, Stephen Finlayson and Ryan Roebuck 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 2019 and for fiscal 2018 by our principal auditors, BDO USA, LLP:

	December 31, 2019	December 31, 2018
Audit Fees:		
Audit of financial statements	$ 615,389	$ 555,580
Services in connection with regulatory filings	6,150	232,346
Total Audit Fees	$ 621,539	$ 787,926

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a)1. Financial Statements:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2019 and December 31, 2018.
Consolidated Statements of Operations for the years ended December 31, 2019 and December 31, 2018.
Consolidated Statements of Comprehensive Income for the years ended December 31, 2019 and December 31, 2018.
Consolidated Statements of Cash Flows for the years ended December 31, 2019 and December 31, 2018.
Consolidated Statement of Changes in Shareholders' Equity for the years ended December 31, 2019 and December 31, 2018.
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.
3.2	Bylaws of Epsilon Energy Ltd.
3.3	Articles of Amendment dated December 19, 2018
4.1*	Description of Registrant's Securities Registered Under Section 12 of the Exchange Act.
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
10.2	First Amendment to Credit Agreement, effective as of December 10, 2015
10.3	Second Amendment to Credit Agreement, effective as of October 11, 2016
10.4	Third Amendment to Credit Agreement, effective as of February 21, 2018
10.5	Fourth Amendment to Credit Agreement, effective as of August 4, 2018
10.6	Fifth Amendment to Credit Agreement, effective as of January 7, 2020
10.7+	Lane Bond Offer Letter
10.8+	Henry Clanton Offer Letter
10.9	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
10.10+	Amended and Restated 2017 Stock Option Plan
10.11+	Share Compensation Plan

10.12	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
21.1	Subsidiaries of the Registrant
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*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* 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 18, 2020.

EPSILON ENERGY LTD.

By: /s/ *B. Lane Bond*
B. Lane Bond
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/ Michael Raleigh Michael Raleigh	Chief Executive Officer and Director (Principal Executive Officer)	March 18, 2020
/s/ B. Lane Bond B. Lane Bond	Chief Financial Officer (Principal Financial and Accounting Officer)	March 18, 2020
/s/ John Lovoi John Lovoi	Chairman of the Board	March 18, 2020
/s/ Matthew Dougherty Matthew Dougherty	Director	March 18, 2020
/s/ Stephen Finlayson Stephen Finlayson	Director	March 18, 2020
/s/ Ryan Roebuck Ryan Roebuck	Director	March 18, 2020
/s/ Jacob Roorda Jacob Roorda	Director	March 18, 2020
/s/ Tracy Stephens Tracy Stephens	Director	March 18, 2020