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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2022
or

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

For the transition period from______ to______
Commission File Number: 001-41510

ALPINE SUMMIT ENERGY PARTNERS, INC.
(Exact name of registrant as specified in its charter)

British Columbia	**98-1623755**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)

3322 West End Ave., Suite 450
Nashville, TN
37203
(Address of principal executive offices and zip code)

(346) 264-2900
(Registrant's telephone number, including area code)

None
(Former name, former address and former fiscal year, if changed since last report)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Subordinate Voting Shares	**ALPS**	**The Nasdaq Stock Market LLC**

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

None
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐ [1]

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

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

Aggregate market value of the registrant's common stock held by non-affiliates of the registrant, based upon the closing price of the Class A subordinate voting shares of the registrant on June 30, 2022 as reported on the OTCQX International Market on that date: $180,786,853.

As of March 27, 2023, there were 33,929,921 Class A subordinate voting shares, no par value, of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain parts of the registrant's Definitive Proxy Statement relating to the registrant's 2023 Annual Meeting of Shareholders (the "**2023 Proxy Statement**") are incorporated by reference into Part III of this Annual Report on Form 10-K (the "**Annual Report**").

CONVENTIONS

In this Annual Report on Form 10-K, we use the terms "Alpine Summit," "we," the "Company," "our" and "us" to refer to Alpine Summit Energy Partners, Inc. and its subsidiaries. References herein to "$", "US$" or "dollars" are to United States dollars and references herein to "$Cdn", "C$" or "CDN dollars" are to Canadian dollars. Unless otherwise indicated, all financial information herein has been presented in United States dollars.

[1] Check boxes are blank, pending adoption of the underlying rules.

ALPINE SUMMIT ENERGY PARNTERS, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2022
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FORWARD-LOOKING STATEMENTS

This Annual Report contains certain "forward-looking information" and "forward-looking statements" (together, "**forward-looking statements**"), including management's assessment of Alpine Summit Energy Partner, Inc.'s (the "**Company"** or "**Alpine Summit**") future plans and operations specifically in relation to the remainder of 2023 and 2024. Such forward-looking statements are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "schedule", "indicate", "focus", "outlook", "propose", "target", "objective", "priority", "strategy", "estimate", "budget", "forecast", "would", "could", "will", "may", "future" or other similar words or expressions and include forward-looking statements relating to or associated with individual wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations and financial position. Forward-looking statements are based on expectations, forecasts, and assumptions made by the Company using information available at the time of the statement and historical trends which includes expectations and assumptions concerning: the accuracy of reserve estimates and valuations; performance characteristics of producing properties; access to third-party infrastructure; government policies and regulation; future production rates; accuracy of estimated capital expenditures; availability and cost of labor and services and owned or third-party infrastructure; royalties; development and execution of projects; the satisfaction by third parties of their obligations to the Company; and the receipt and timing for approvals from regulators and third parties. All statements concerning expectations or projections about the future and statements and information regarding the future business plan or strategy, timing or scheduling, production volumes with splits by commodity, production declines, expected and future activities and capital expenditures, commodity prices, costs, royalties, schedules, operating or financial results, future financing requirements, and the expected effect of future commitments are forward-looking statements.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to:

- changes in general economic, business and political conditions, including commodity price volatility, interest rates and currency exchange, OPEC (as defined below) actions, ongoing global economic concerns, Russia's continuing military invasion of Ukraine, and rising civil unrest and activism globally;
- changes in supply and demand for the Company's oil, natural gas, and natural gas liquids ("**NGLs**");
- a global public health crisis including the outbreak of the novel coronavirus (COVID-19) in 2020 which has caused volatility and disruptions in the supply, demand and pricing for crude oil, natural gas, and NGLs, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people;
- volatility of commodity prices and the related effects of changing price differentials;
- ability to access capital from internal and external sources (including the Corporate Credit Facility and the ABS Facility, each as defined below);
- the Company's ability to meet foreseeable obligations by actively monitoring its credit facilities through use of loans/notes, asset sales, coordinating payment and revenue cycles each month, and an active commodity hedge program to mitigate commodity price risk and secure cash flows;
- ability to finance planned activities including infrastructure expansions which are required to meet future growth targets;
- access to third-party pipelines and facilities and access to sales markets;
- the ability to obtain regulatory, stakeholder and third-party approvals and satisfy any associated conditions that are not within the Company's control for exploration and development activities and projects;
- the ability of the Company to execute the normal course issuer bid ("**NCIB**");
- successful and timely implementation of capital expenditures;
- risks associated with the development and execution of major projects;
- risk that projects and opportunities intended to grow cash flow and/or reduce costs may not achieve the expected results in the time anticipated or at all;
- the Company's ability to operate and access to facilities to meet forecast production;
- the ability of the Company to pay dividends to its shareholders;
- the timing of payments in respect of the various development partnerships;

- operational risks and uncertainties associated with crude oil, natural gas, and NGLs activities, including unexpected formations or pressures, reservoir performance, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of natural gas and wellbore fluids, pollution and other environmental risks;
- hanges in costs including production, royalty, transportation, general and administrative, and finance;
- adverse weather conditions which could disrupt production and affect drilling and completions resulting in increased costs and/or delay adding production;
- actions by government authorities including changes to taxes, fees, duties and government-imposed compliance costs;
- hanges to laws and government policies including environmental (and climate change), royalty, and tax laws and policies;
- ounter-party risk with third parties to perform their obligations with whom the Company has material relationships;
- unplanned facility maintenance or outages or unavailability of third-party infrastructure which could reduce production or prevent the transportation of products to processing plants and sales markets;
- a major outage or environmental incident or unexpected event such as fires (including forest fires), hurricanes or equipment failures or similar events that would affect the Company's facilities or third-party infrastructure used by the Company;
- environmental risks (including climate change) and the cost of compliance with current and future environmental laws, including climate change laws along with risks relating to increased activism and opposition to fossil fuels;
- the risk that competing business objectives may exceed the Company's capacity to adapt and implement change;
- the potential for security breaches of the Company's information technology systems by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches;
- risks with transactions including closing an asset or property acquisition or disposition and the failure to realize anticipated benefits from any transaction;
- finding new crude oil and natural gas reserves that can be developed economically to replace reserves depleted by production;
- the accuracy of estimating reserves and future production and the future value of reserves;
- risk associated with commodity price hedging activities using derivatives and other financial instruments;
- maintaining debt levels at a reasonable multiple of cash flow;
- risk that the Company may be subject to litigation;
- the accuracy of cost estimates, some of which are provided at an early stage and before detailed engineering has been completed;
- risk associated with partner or joint arrangements to which the Company is a party;
- inability to secure labor, services or equipment on a timely basis or on favourable terms;
- increased competition from other industry participants for, among other things, capital, acquisitions of assets or undeveloped lands, and skilled personnel; and
- increased competition from companies that provide alternative sources of energy.

Statements relating to "reserves" or "resources" are forward-looking statements, including financial measurements such as net present value, as they involve the assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. The Company disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under applicable securities law.

Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

PART I

ITEM 1. BUSINESS

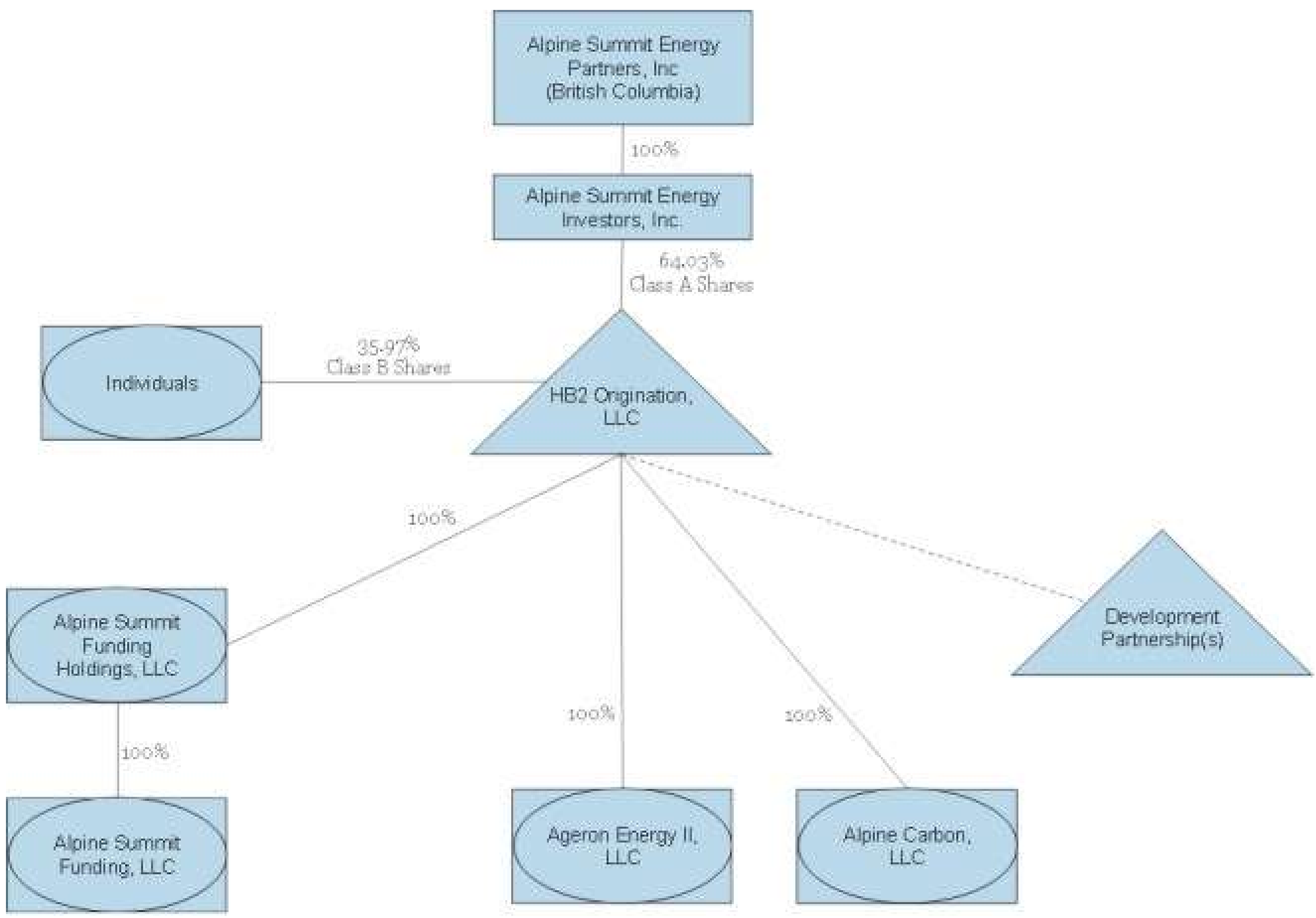
Background

The Company was incorporated under the *Business Corporations Act* (British Columbia) (the "**BCBCA**") on July 30, 2008 under the name "Red Pine Petroleum Ltd."

On April 8, 2021, the Company entered into the business combination agreement (the "**Business Combination Agreement**") pursuant to which Red Pine Petroleum Ltd. agreed to complete a series of transactions to effect a combination between the company and HB2 Origination, LLC ("**Origination**" or "**HB2**"), and changed its name to "Alpine Summit Energy Partners, Inc." upon completion of the transaction. These series of transactions resulted in a reverse take-over (the "**RTO**") of the Company by the mebers of origination.

Alpine Summit's Class A subordinate voting shares (the "**Subordinate Voting Shares**") are listed on the TSX Venture Exchange (the "**TSXV**") under the symbol "ALPS.U" and the Nasdaq Global Market (the "**Nasdaq**") under the symbol "ALPS".

The following organizational chart illustrates the inter-corporate relationships among the Company and its subsidiaries as of December 31, 2022. See Exhibit 21.1 to this Annual Report for a list of subsidiaries of the Company.



The Company's head office is located at 3322 West End Ave., Suite 450, Nashville, Tennessee 37203. The registered office of the Company is located at Suite 2200, HSBC Building, 885 West Georgia St., Vancouver, British Columbia, V6C 3E8.

General Development of the Business

January 2023 - March 2023

On January 20, 2023, the Company announced the successful payout and liquidation of its fifth development partnership that it formed during the second quarter of 2022 (the "**Fifth Development Partnership**"), along with the concurrent closing of its seventh development partnership (the "**Seventh Development Partnership**"). The Fifth Development Partnership partially funded the drilling and completion of a total of six wells and comprised a total capital program of approximately US$50.3 million, with 60% funded by external partners. As part of the completion of the Fifth Development Partnership, the Company retired redeemable non-controlling interests of approximately US$36.4 million, after previous distributions of $0.5 million. The Seventh Development Partnership has an expanded capital program of approximately US$57.1 million, with approximately US$34.3 million of external development capital, and is expected to continue to develop assets within the Company's existing operational footprint.

On February 3, 2023, the Company announced that it had completed an exercise by six partners of the put right provided to such partners by the Fifth Development Partnership. In connection with the exercise, 499,794 Class B non-voting units of Origination ("**HB2 Units**") (exchangeable on a one-for-one basis for Subordinate Voting Shares) were issued to these partners. Two of the partners from the Fifth Development Partnership partners exchanged their interests at a deemed value of US$5.23 per unit and the remaining four DP5 partners exchanged their interests at a deemed value of US$5.01 per unit.

On February 23, 2023, the Company announced that the Board of Directors of the Company (the "**Board**") had commenced a strategic review of its assets. The Company is seeking to facilitate a timely and orderly response to unsolicited inquiries by other upstream oil and natural gas companies who have expressed interest in acquiring various assets of the Company. The Board also deemed it prudent to suspend its monthly dividend payments beginning in March 2023.

On March 3, 2023, the Company announced that Darren Tangen had resigned from its Board, including its Compensation, Audit and Operations and Reserves Committees, effective March 2, 2023. In connection with the resignation, James Russo was appointed as a member of the Board as well as a member of the Compensation, Audit and Operations and Reserves Committees to fill the vacancy created by Darren Tangen's resignation.

On March 8, 2023, the Company announced that it had engaged Stephens Inc. as its financial advisor to pursue an asset sale for various strategic, high producing assets recently developed and proven by the Company. Proceeds of such sale are expected to retire existing liabilities as well as place additional capital on the Company's balance sheet.

On March 10, 2023, HB2 entered into an Omnibus Waiver (the “**Waiver**”) to the corporate credit facility with Bank7 Corp. (the "**Corporate Credit Facility**"). The Waiver grants HB2 a waiver of all covenants contained in Article VII of the Corporate Credit Facility and makes certain other conforming changes.

On March 21, 2023, HB2 amended and restated the Omnibus Waiver Agreement (the “**Amended Waiver**”) and entered into an extension to the Corporate Credit Facility (“**Extension Agreement**”). The Extension Agreement and the Amended Waiver extend the final maturity date of the Corporate Credit Facility to July 1, 2023 and grant HB2 a waiver of all covenants contained in Article VII of the Corporate Credit Facility through July 1, 2023 and makes certain other conforming changes.

On March 23, 2023, the Company amended its asset-backed securitization facility of certain producing oil and gas wells (the “**ABS Facility**”) to, among other things, suspend certain covenants, including with respect to the debt service coverage ratio, the production tracking rate and the loan-to-value requirement, until July 1, 2023, and to extend the initial maturity date of the first tranche of the ABS Facility until July 1, 2023.

Year Ended December 31, 2022

On January 4, 2022, the Company announced that, effective December 31, 2021, the Subordinate Voting Shares commenced trading on the OTCQB under the symbol "ASEPF."

On January 10, 2022, the Company announced the successful payout and liquidation of its second development partnership (the "**Second Development Partnership**"), along with the concurrent closing of its fourth development partnership (the "**Fourth Development Partnership**"). The Second Development Partnership funded the drilling and completion of five wells in the Giddings Field near Austin, TX and comprised a total capital program of approximately US$35.2 million, with 60% funded by external partners. As part of the completion of the Second Development Partnership, the Company retired redeemable non-controlling interests of approximately US$23.5 million, after previous distributions of US$4.5 million. The Fourth Development Partnership had an expanded capital program of approximately US$42.0 million, with approximately US$25.2 million of external development capital, and was used to develop assets within the Company's existing operational footprint.

On March 10, 2022, the Company announced the closing of a new development partnership by Origination ("**Red Dawn 1**"). Red Dawn 1 had a capital plan of approximately US$50.4 million, with approximately US$30.3 million of external development capital, and was used to partially fund the drilling and completion of five wells.

On March 14, 2022, the Company announced the closing of the Corporate Credit Facility by its operating subsidiary, Origination. The Corporate Credit Facility, led by Bank7 Corp. ("**Bank7**"), replaced the October 2021 Facility (defined below). The Corporate Credit Facility had a total size of US$30 million. The Corporate Credit Facility is secured by working interests in a subset of the Company's producing assets and charges interest at the greater of 5.00% and Prime +1.75%. The Corporate Credit Facility, which has a one-year maturity, is expected to provide the Company with additional working capital flexibility.

On April 27, 2022, the Company announced the successful payout and liquidation of its third development partnership (the "**Third Development Partnership**"), along with the concurrent closing of its Fifth Development Partnership. The Third Development Partnership funded the drilling and completion of a total of five wells: three wells in the Giddings Field near Austin, TX and two wells in Webb County, TX; and comprised a total capital program of approximately US$35.3 million, with 60% funded by external partners. As part of the completion of the Third Development Partnership, the Company retired redeemable non-controlling interests of approximately US$30.2 million. The Fifth Development Partnership expanded its capital program by approximately US$50.3 million, with approximately US$30.2 million of external development capital, is expected to continue to develop assets within the Company's existing operational footprint. Additionally, twelve partners of the Third Development Partnership exercised the put right provided to such partners by the Third Development Partnership regarding residual interests in their associated investment and elected to sell their remaining interest in the Third Development Partnership for 894,929 Class B non-voting units of Origination (exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company), with a deemed value of US$5.70 per unit (which was calculated with reference to the trailing 30 day share price and the allowable discounts permitted by the policies of the TSXV), or a total of approximately US$5.1 million.

On May 2, 2022, the Company announced the successful closing of the ABS Facility. The ABS Facility is led by an insurance company and had an initial size of US$80 million with additional capacity to expand up to US$150 million in total. The ABS Facility is secured by working interests in a subset of the Company's producing assets, which are held by an affiliate of its operating subsidiary, Origination, and charges interest at LIBOR + 6.00% (with a 1% LIBOR floor) for the initial year, and LIBOR +12% (with a 1% LIBOR floor) for the second year. Proceeds from the ABS Facility were used to repay existing indebtedness, the Company's asset backed preferred instrument in connection with the Shareholder Takeout (discussed below), and for general corporate purposes.

On May 20, 2022, the Company announced that the exercise by twelve partners of the put right provided by the Third Development Partnership was completed. In connection with the exercise, 894,929 Class B non-voting units of Origination (exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company) were issued to these partners on May 19, 2022, at a deemed value of US$5.70 per unit.

On June 7, 2022, the Company announced that it received approval from the TSXV of its Notice of Intention to Make an NCIB. Under the NCIB, the Company may purchase for cancellation up to 1,648,783 Subordinate Voting Shares over a 12-month period commencing on June 10, 2022. The NCIB will expire no later than June 9, 2023. The price that Alpine Summit will pay for Subordinate Voting Shares in open market transactions will be the market price at the time of purchase. Any Subordinate Voting Shares that are purchased under the NCIB will be cancelled. The actual number of Subordinate Voting Shares that may be purchased and the timing of such purchases will be determined by the Company. Decisions regarding purchases will be based on market conditions, share price, best use of available cash, and other factors. The Company appointed Leede Jones Gable Inc. to make purchases under the NCIB on its behalf.

On June 13, 2022, the Company announced it was approved for graduation from Tier 2 issuer status to Tier 1 issuer status on the TSXV, effective June 14, 2022. Concurrently with the graduation to a Tier 1 listing on the TSXV, the TSXV also accepted the Company's application to release the securities previously deposited into escrow on the basis that the Company has a market capitalization in excess of CAD$100 million and therefore was considered an "exempt issuer" under National Policy 46-201.

On July 15, 2022, the Company announced the successful payout and liquidation of the Fourth Development Partnership, along with the concurrent closing of its sixth development partnership (the "**Sixth Development Partnership**"). The Fourth Development Partnership funded the drilling and completion of a total of five wells: three wells in the Giddings Field near Austin, TX and two wells in Webb County, TX; and comprised a total capital program of approximately US$35.2 million, with 60% funded by external partners. As part of the completion of the Fourth Development Partnership, Alpine Summit had retired redeemable non-controlling interests of approximately US$ 31.7 million, after previous distributions of $2.7 million. The Sixth Development Partnership expanded its capital program to approximately US$56.9 million, with approximately US$34.2 million of external development capital, and expected to continue to develop assets within the Company's existing operational footprint.

On July 27, 2022, the Company announced that it completed the previously announced exercise by nine partners of the put right provided by the Fourth Development Partnership. 706,975 Class B non-voting units of Origination (exchangeable on a one-for one basis for Subordinate Voting Shares of the Company) were issued to these partners on July 26, 2022, at a deemed value of US$5.85 per unit.

On September 13, 2022, the Company announced the successful expansion of its asset backed securitization of certain producing oil and natural gas wells. The ABS Facility was increased by US$55 million, to a total size of US$135 million, with additional capacity to expand up to US$150 million in total. The ABS Facility is secured by working interests in a subset of the Company's producing assets, which are held by an affiliate of its operating subsidiary, Origination, and charges interest at LIBOR + 8.00% (with a 1% LIBOR floor) for the initial year, and LIBOR + 14% (with a 1% LIBOR floor) for the second year. Proceeds from the ABS Facility are used for continued development activities, working capital, and general corporate purposes.

On September 26, 2022, the Company announced that the Nasdaq Stock Market LLC approved the Company's application to list its Subordinate Voting Shares on Nasdaq, with the Subordinate Voting Shares commencing trading on Nasdaq at the opening of the market on September 28, 2022, under the ticker symbol "ALPS."

On September 27, 2022, the Company announced that the TSXV approved an amendment to the NCIB, which commenced on June 10, 2022 and will conclude on the earlier of the date on which purchases under the NCIB have been completed and June 9, 2023. The NCIB was amended to reflect that the Company is permitted to enter into an automatic share purchase plan ("**ASPP**") with its designated broker, Leede Jones Gable Inc., to facilitate the purchase of its Subordinate Voting Shares under the NCIB during times when the Company would not ordinarily be permitted to purchase such shares due to regulatory restrictions or self-imposed black-out periods. All other terms and conditions of the NCIB remained the same.

On October 4, 2022, the Company announced the successful expansion of the Corporate Credit Facility, which originally had a total size of US$30 million (as announced on March 14, 2022). The Corporate Credit Facility was increased to a total size of US$65 million and as of that date had a borrowing base availability of US$17.4 million. The Corporate Credit Facility's maturity date and interest rate remained unchanged.

On November 10, 2022, the Company announced the successful payout and liquidation of Red Dawn 1 that it formed during the first quarter of 2022, along with the concurrent closing of another development partnership ("**Red Dawn 2**"). Red Dawn 1 partially funded the drilling and completion of a total of five wells and comprised a total capital program of approximately US$50.4 million, with 60% funded by external partners. As part of the completion of the Red Dawn 1 program, the Company retired redeemable non-controlling interests of approximately US$38.5 million. Red Dawn 2 has an expanded capital program of approximately US$57.7 million, with approximately US$34.6 million of external development capital, and is expected to continue to develop assets within the Company's existing operational footprint.

On December 1, 2022, the Company announced that twelve Red Dawn 1 partners exercised the put right provided to such partners by Red Dawn 1, regarding residual interests in their associated investment. In connection with the exercise, 617,103 Class B non-voting units of Origination (exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company) were issued to these partners, at a deemed value of US$5.16 per unit.

On December 13, 2022, the Company announced that the board of directors of the Company approved the Company's capital return program for 2023, which consisted of: i) increasing the existing monthly dividend by 5% and ii) continuing the share buyback program under the previously announced and approved NCIB.

Year Ended December 31, 2021

Shareholder Takeout

On March 5, 2021, the Company implemented an equity buy-back structure, under which a controlling unitholder exchanged 100% of their holdings (being 3,992,629 membership units of Origination, which represented approximately 23.4% of Origination's membership units at the time) along with a US$1,000,000 promissory note for asset-backed preferred instruments (each, a "**Preferred Instrument**") issued by AIP Holdco, LP (with a total of 23,500,000 Preferred Instruments issued). The remaining Preferred Instruments were redeemed at a price of US$1.00 per Preferred Instrument.

The Preferred Instruments were not convertible into shares of Alpine Summit (being the resulting issuer after completion of the "RTO") and had no governance rights. The Preferred Instruments were not secured obligations, and a default would have only resulted in increased fixed rate of return.

Development Partnerships

The Company, through its wholly owned subsidiary Origination, sponsors and manages development programs to participate in its drilling initiatives and accelerate its growth. Most of Origination's drilling programs are limited partnerships structured to minimize drilling risks on repeatable prospects and optimize tax advantages for private investors. At the commencement of production of a well, Origination assigns working interest rights for such well to an operating partnership.

During the first quarter of 2021, Origination formed a development partnership (the "**First Development Partnership**") with 13 limited partners (the "**First Partnership LPs**") and certain wholly-owned subsidiaries of Origination as limited partners and the general partner, which was US$21.8 million in total size. The First Development Partnership funded the drilling and completion of five wells, with the First Partnership LPs funding 60% and Origination funding 40%. The First Partnership LPs could choose to receive development partnership units ("**DP Units**") that distributed profits either based on a Flat payout option or an IRR based payout option. Flat Payout Units participated in 75% of the income of the First Development Partnership (along with IRR based Payout Units) until that income equaled their invested capital and thereafter participated in 20% of the income of the First Development Partnership (along with IRR based Payout Units). IRR Based Payout Units participated in 75% of the income of the First Development Partnership (along with Flat Payout Units) until that income equaled their invested capital plus a 15% annualized return on invested capital or 120% of their initial investment, whichever was greater and thereafter participated in 6% of the income of the First Development Partnership, along with Flat Payout Units, which participated in 20% of the income of the First Development Partnership. The First Partnership LPs also had a put right to effectively sell their remaining interest for HB2 Units or cash, subject to the consent of Origination and certain other restrictions, for an amount calculated at the net future present values on oil and natural gas reserve estimates.

During the second quarter of 2021, Origination formed its Second Development Partnership with 25 limited partners (the "**Second Partnership LPs**") and certain wholly-owned subsidiaries of Origination as limited partners and the general partner, which was US$35.2 million in total size. The Second Development Partnership funded the drilling and completion of five wells, with the Second Partnership LPs funding 60% and Origination funding 40%. The Second Partnership LPs could choose to receive development partnership units ("**DP Units**") that distributed profits either based on a Flat payout option or an IRR based payout option. Flat Payout Units participated in 75% of the income of the Second Development Partnership (along with IRR based Payout Units) until that income equaled their invested capital and thereafter participated in 20% of the income of the Second Development Partnership (along with IRR based Payout Units). IRR Based Payout Units participated in 75% of the income of the Second Development Partnership (along with Flat Payout Units) until that income equaled their invested capital plus a 15% annualized return on invested capital or 120% of their initial investment, whichever was greater and thereafter participated in 6% of the income of the Second Development Partnership, along with Flat Payout Units, which participated in 20% of the income of the Second Development Partnership. The Second Partnership LPs also had a put right to effectively sell their remaining interest for HB2 Units or cash, subject to the consent of Origination and certain other restrictions, for an amount calculated at the net future present values on oil and natural gas reserve estimates.

On October 7, 2021, the Company announced the successful payout and liquidation of the First Development Partnership, along with the concurrent closing of Third Development Partnership. As part of the completion of the First Development Partnership, Alpine Summit had retired redeemable non-controlling interests of approximately US$15.3 million, after previous distributions of $1.9 million.

Origination formed the Third Development Partnership with 23 limited partners (the "**Third Partnership LPs**") and certain wholly-owned subsidiaries of Origination as limited partners and the general partner, which was US$34.7 million in total size. The Third Development Partnership funded the drilling and completion of five wells, with the Third Partnership LPs funding 60% and Origination funding 40%. The Third Partnership LPs could choose to receive development partnership units ("**DP Units**") that distributed profits either based on a Flat payout option or an IRR based payout option. Flat Payout Units participated in 75% of the income of the Third Development Partnership (along with IRR based Payout Units) until that income equaled their invested capital and thereafter participated in 20% of the income of the Third Development Partnership (along with IRR based Payout Units). IRR Based Payout Units participated in 75% of the income of the Third Development Partnership (along with Flat Payout Units) until that income equaled their invested capital plus a 15% annualized return on invested capital or 120% of their initial investment, whichever is greater and thereafter participated in 6% of the income of the Third Development Partnership, along with Flat Payout Units, which participated in 20% of the income of the Third Development Partnership. The Third Partnership LPs also had a put right to effectively sell their remaining interest for HB2 Units or cash, subject to the consent of Origination and certain other restrictions, for an amount calculated at the net future present values on oil and natural gas reserve estimates.

Convertible Promissory Notes

During the year ended December 31, 2021, Origination issued $1,075,000 in promissory notes for cash of which $75,000 were to an officer of the Company.

During the year ended December 31, 2021, Origination issued 353,870 HB2 Units in exchange for $3,475,000 in promissory notes of which $600,000 were held by an officer of the Company. In addition, Origination exchanged $1,000,000 of promissory notes in connection with the asset backed preferred instrument (see Shareholder Takeout section).

During the year ended December 31, 2021, Origination repaid $1,755,000 of promissory notes with cash and also offset $270,000 of promissory notes with agreed upon overhead expenses, which was shown as a reduction of general and administrative expenses.

In June 2021, Origination issued a series of unsecured, non-interest-bearing convertible promissory notes to individuals in aggregate principal amount of $2.3 million with a maturity date of sixty days from the date of issuance. Per the terms of these convertible promissory notes, they were convertible into units of Origination at a conversion rate of $9.82/unit at the option of the noteholder or Origination. On July 2, 2021, Origination exercised its option to convert all the existing convertible notes into 234,216 HB2 Units effective as of July 7, 2021.

Other Developments

On August 18, 2021, Alpine Summit Energy Partners Finco, Inc. ("**Finco**") completed a brokered private placement of an aggregate of 161,976 Subordinate Voting Subscription Receipts at a subscription price of C$4.01 per Subordinate Voting Subscription Receipt and 17,057 Multiple Voting Subscription Receipts at a subscription price of C$401.29 per Multiple Voting Subscription Receipt for aggregate gross proceeds of approximately C$7.5 million. After deducting the agent's fees and expenses incurred in connection with the offering, the net proceeds of the Finco Financing were approximately C$7.2 million. The Company used the net proceeds of the Finco Financing principally to fund the general working capital of the Company. On October 28, 2021, the Company announced that its operating subsidiary, Origination, entered into a new corporate credit facility (the "**October 2021 Facility**") with a total size of up to US$12.5 million with a one-year maturity. The October 2021 Facility was secured by working interests in a subset of the Company's producing assets and charged interest of prime +2.25%.

On December 14, 2021, in accordance with its current monthly dividend policy, the Company declared a dividend of $0.03 per Subordinate Voting Share for the month of January 2022. Simultaneously with declaring the dividend on the Subordinate Voting Shares, the Company also declared a dividend on the Multiple Voting Shares equal to $3.00 per share and a dividend on the Proportionate Voting Shares equal to $0.03 per share. The dividend was payable on January 31, 2022, to the shareholders of record at the close of business on January 17, 2022.

Significant Acquisitions

Except for the RTO, the Company did not complete any individually significant acquisitions during the year ended December 31, 2021.

Description of the Business

General

Alpine Summit is a U.S. oil and natural gas development company that operates and develops oil and gas wells. Alpine Summit focuses its drilling activity in two main areas, the Austin Chalk and Eagle Ford formations in the Giddings Field in Austin, Fayette, Lee, Robertson and Washington Counties, TX (the "**Giddings Assets**") and the Hawkville Field in Webb and LaSalle Counties, TX (the "**Hawkville Assets**"), both well-positioned acreage locations in Texas which have produced substantial amounts of oil, natural gas, and NGLs for decades.

Alpine Summit distributes its commodity products through a network of marketing agreements covering its oil, natural gas, and NGLs. In general, these marketing agreements provide for Alpine Summit to receive prices that are referenced relative to highly visible and transparent benchmark prices and the Company is not reliant upon any single significant customer.

Alpine Summit enjoys a competitive advantage to other natural gas producers in the United States by virtue of its access to gulf coast natural gas markets without significant basis differentials. Alpine Summit anticipates being a beneficiary of the announced expansion of significant LNG export terminals in this area commencing in late Q4 2024 and well into 2026, since it views substantial expansion of interstate pipelines from other basins as unlikely.

Alpine Summit has become one of the more experienced energy operators in the Giddings and Hawkville Field areas and is complemented by a seasoned leadership team and a proven operating team. The Company's development history has enabled it to maintain a breadth of service provider contacts without undue reliance on any single service provider. The Company's employees are non-unionized and its service providers work on a contract basis.

The Company's ability to develop assets depends on its maintenance of ongoing lease obligations with groups of mineral rights owners throughout the state of Texas. These royalty and access agreements govern its surface and drilling operations and Alpine Summit must stay in continuous compliance to effectuate its business. Further, prior to beginning additional development work, the Company must file all applicable regulatory paperwork with the relevant regulatory body, namely the Texas Railroad Commission, in order obtain valid drilling permits. The Company is also required to comply with all applicable federal, state and county regulations while drilling wells in addition to when developed assets are on production. The Company believes it is in good standing with relevant regulatory bodies and does not foresee any imminent changes to applicable policy or procedures that would impact operations.

On February 23, 2023, the Company announced that the Board had commenced a strategic review of its assets and on March 8, 2023, the Company announced that it had engaged Stephens Inc. as its financial advisor to pursue an asset sale for the Hawkville Assets. Other than completing existing in-process wells, the Company expects to pause field activity until the completion of the sales process. The Company plans to focus on developing its existing and adjacent footprint over the next several years while also evaluating additional development projects that fit its investment criteria.

Specialized Skill and Knowledge

The Company relies on the specialized skill and knowledge of its management and staff to compile, interpret and evaluate technical data, drill and complete wells, design and operate production facilities and numerous additional activities required to explore for and produce oil, natural gas, and NGLs. From time to time, the Company employs consultants and other service providers to provide complementary experience and expertise to carry out its oil, natural gas, and NGL operation effectively. It is the belief of management of the Company that its officers and employees, who have significant technical, operational and financial experience in the oil and natural gas industry, hold the necessary skill sets to successfully execute the Company's business strategy in order to achieve its corporate objectives.

Competition

The oil and natural gas industry is competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil, natural gas, and NGLs. The Company's competitors include resource companies which have greater financing resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil, natural gas, and NGLs include price, methods, and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and natural gas issuers of similar size and at a similar stage of development.

Cyclical and Seasonal Impact of Industry

The Company's operational results and financial condition are dependent on the prices received for its oil, natural gas, and NGL production. Oil, natural gas, and NGL pricing have fluctuated widely during recent years. Commodity prices are determined by supply and demand, geopolitical factors, weather and general economic conditions, as well as conditions in other oil and natural gas regions. Declining prices in oil, natural gas, and NGLs could have an adverse effect on the Company's financial condition. In addition, the development of oil and natural gas reserves is dependent on access to areas where drilling and other oilfield operations are to be undertaken.

Government Regulations

The oil and natural gas industry is subject to extensive controls and regulations governing its operations imposed by legislation enacted by various levels of government, all of which should be carefully considered by investors in the oil and natural gas industry. Numerous governmental entities, including the U.S. Environmental Protection Agency ("**EPA**"), the U.S. Occupational Safety and Health Administration ("**OSHA**") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly action. Since these requirements apply to all operators in the oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected in a manner materially different than that of other oil and natural gas companies of similar size. All legislation and regulation are a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted.

These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (iv) impose specific safety and health criteria addressing worker protection; and (v) impose substantial liabilities for pollution resulting from drilling and completion activities.

Significant existing environmental and occupational health and safety laws and regulations include the following U.S. laws and the regulations promulgated to implement and enforce them, as amended from time to time:

- the Clean Air Act ("**CAA**"), which restricts the emission of air pollutants from many sources and imposes various operational, monitoring, and reporting requirements and has been relied upon by the EPA as authority for adopting climate change regulatory initiatives relating to greenhouse gas ("GHG") emissions;
- the Federal Water Pollution Control Act, also known as the federal Clean Water Act, which regulates discharges of pollutants to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("**CERCLA**"), which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- the Resource Conservation and Recovery Act ("**RCRA**"), which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- the Safe Drinking Water Act ("**SDWA**"), which ensures the quality of the nation's public drinking water through *inter alia*, controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;

- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories; and
- the Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

Compliance with federal environmental or occupational health and safety legislation and comparable state laws, as well as local ordinances including those pertaining to land use, zoning, building, and transportation requirements, can require significant expenditures or operational restrictions. Breach of such requirements may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage or personal injury, and the imposition of material fines, administrative, civil and criminal penalties, and remediation costs, all of which have the potential to negatively impact the Company's earnings and corporate growth. The Company maintains an active list of its expected future expenditures to reclaim its properties to acceptable regulatory standards. The expected future obligation is not outside the norm for a company of its size and operations. The Company has internal procedures designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding with them.

Employees

As of December 31, 2022, the Company had 26 full-time employees.

Reorganizations

The following is a summary of the Business Combination. This summary is qualified in its entirety by the terms of the Business Combination Agreement which is available under the Company's profile on EDGAR at www.sec.gov/edgar.

On April 8, 2021, the Company, Origination, Finco, Red Pine Petroleum Subco Ltd. ("**Subco**") and Alpine Summit Energy Investors, Inc. ("**Blocker**") entered into the Business Combination Agreement pursuant to which the parties agreed to complete a series of transactions to affect a business combination between the Company (through its predecessor Red Pine Petroleum Ltd.) and Origination and that resulted in a reverse take-over of the Company by the members of Origination.

The principal steps of the RTO were as follows:

(1) Finco issued Subscription Receipts for gross proceeds of approximately CDN$7,500,000;

(2) immediately prior to the closing of the RTO:

  (a) the Company amended its articles to (i) reclassify its common shares as Subordinate Voting Shares, (ii) create a new class of Multiple Voting Shares and a new class of Proportionate Voting Shares, and (iii) change its name from "Red Pine Petroleum Ltd." to "Alpine Summit Energy Partners, Inc." and, immediately thereafter, effected the Consolidation;

  (b) each outstanding membership unit of Origination was converted into three membership units of Origination (the "**Recapitalization**");

  (c) the Subscription Receipts were converted into Finco Shares, with each holder of a Subordinate Voting Subscription Receipt receiving one Class A Finco Share in exchange therefor and each holder of a Multiple Voting Subscription Receipt receiving one Class B Finco Share in exchange therefor; and

(3) on closing of the RTO:

(a) the Company, Finco and Subco completed a three-cornered amalgamation under the BCBCA pursuant to which all Finco shareholders (including former holders of the Subscription Receipts) exchanged their Class A Finco Shares for Subordinate Voting Shares or their Class B Finco Shares for Multiple Voting Shares, as applicable, in each case on a one-for-one basis, and Finco and Subco amalgamated, with the resulting entity ("**Amalco**") to continue as a wholly-owned subsidiary of the Company;

(b) Amalco was wound up into the Company and the assets of Amalco (which consisted of the funds invested by the holders of the Subscription Receipts, net of expenses) were transferred to the Company by operation of law;

(c) certain U.S. holders of membership units in Origination (other than Blocker) contributed their membership units in Origination to the Company in exchange for Multiple Voting Shares on a one-hundred membership units (post-Recapitalization) for one Multiple Voting Shares basis;

(d) certain of the non-U.S. holders of membership units in Origination contributed their membership units in Origination to the Company in exchange for Subordinate Voting Shares on a one membership unit (post-Recapitalization) for one Subordinate Voting Share basis subject to adjustment for any applicable withholding taxes;

(e) each holder of Blocker Shares contributed their Blocker Shares to the Company in exchange for Subordinate Voting Shares on a one Blocker Share for three Subordinate Voting Shares basis;

(f) the Initial Holder subscribed for Proportionate Voting Shares carrying voting rights that, in the aggregate, represented approximately 32% of the voting rights of the Company upon completion of the RTO on a fully diluted basis for a purchase price equivalent to their fair market value;

(g) the Company used certain proceeds of the Finco Financing and the membership units of Origination received by it to subscribe for Blocker Shares, following which the proceeds of Finco Financing received by Blocker were contributed to Origination in exchange for membership units of Origination; and

(h) membership units of Origination held by Blocker were re-designated as Class A Voting Units of Origination and membership units of Origination held by other remaining members of Origination will be re-designated as Class B Non-Voting Units of Origination.

Available Information

Our website address is https://www.alpinesummitenergy.com.

ITEM 1A. RISK FACTORS

Risk Factor Summary

Below is a summary of the principal factors that make an investment in our Subordinate Voting Shares speculative or risky, but does not address all of the risks that we face. Additional discussion of the risks summarized below, and other risks that we face, may be found immediately following this summary.

Risks Related to our Business

- We are largely dependent on crude oil, natural gas, and NGL pricing, which may affect the value of the Company's assets and its ability to pursue its business objectives.
- Lower commodity prices may disrupt the production of crude oil, natural gas, and NGL reserves at an acceptable level of profitability.
- We may be unable to obtain additional funding in order to carry out our oil, natural gas, and NGL acquisition and development activities.
- Adverse well or reservoir performance could result in reduced corporate volumes and revenues.
- Our crude oil, natural gas, and NGL development and production activities depend, to one degree or another, on adequate infrastructure and the availability of drilling and related equipment in the particular areas where such activities will be conducted.
- The marketability of our production depends in part on the availability, proximity and capacity of gathering and transportation pipeline facilities.
- Our development programs require sophisticated and scarce technical skills as well as capital and access to land and oilfield service equipment and may not result in the discovery of economic reserves.
- Our current and future development and production activities require the handling of volatile liquids and gases, which may lead to environmental, health and safety risks.
- Oil, natural gas, and NGL development involves a high degree of risk and there is no assurance that expenditures made on development by the Company will result in new discoveries of oil, natural gas, or NGLs in commercial quantities.
- We cannot guarantee that the Company's future development efforts will result in the discovery and development of oil and natural gas reserves.
- As a holding company, we are subject to the risks attributable to each of our subsidiaries.
- We may not be able to keep pace with technological developments in the oil and natural gas industry.
- Estimates of economically recoverable crude oil, natural gas reserves, and NGLs, and related future net cash flows, are based upon a number of variable factors and assumptions that may turn out to be inaccurate, which can materially affect the quantities and present value of our reserves.
- Fuel reduction regulations, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for crude oil and liquid hydrocarbons.
- Any environmental damage, loss of life, injury or damage to property caused by the Company's operations could damage our reputation in the areas in which the Company operates.
- A negative shift in investor or shareholder sentiment of the oil and natural gas industry could adversely affect our business and ability to raise debt and equity capital.
- The success of the Company's business is highly dependent on its ability to finding, developing, and acquiring petroleum and natural gas reserves in a cost-efficient manner.
- We may be unable to obtain all necessary registrations, permits, and authorizations that are required to carry out development at our properties.

Macroeconomic and Financial Risks

- Our Corporate Credit Facility and ABS Facility (collectively, "**Debt Facilities**") contain a number of restrictive covenants that impose significant operating and financial restrictions on the Company.
- Market conditions, weakening global relationships can impact the prices for crude oil, natural gas, and NGLs
- The discontinuation of LIBOR may adversely affect the value of the ABS Facility Notes or the cost of our borrowings.

Legal and Regulatory Risks

- In the United States, the energy industry is subject to scrutiny, frequently hostile, by political and environmental groups, which may lead to increased regulation and increased compliance costs.
- We are subject to stringent federal and state laws and regulations related to labor and occupational health and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations.
- We may be subject to regulations that restricts our ability to discharge water produced as part of our production operations.
- 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 international conventions and national, state and local laws and regulations.
- Climate change, environmental, social and governance and sustainability initiatives may result in regulatory or structural industry changes and/or could result in increased operating costs and reduced demand for the oil, natural gas, and NGLs that we produce while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Risks Related to Ownership of our Subordinate Voting Shares

- Our Board may modify or revoke the declaration and payment of our dividends at any time at its discretion.
- Our principal shareholder and executive officers have the ability to control or significantly influence all matters submitted to the Company's shareholders for approval, including the election of directors.
- Directors and officers of the Company may also be directors and officers of other oil and natural gas companies involved in oil and natural gas exploration and development, and conflicts of interest may arise.

Certain Tax Risks

- The Company anticipates being subject to taxation both in Canada and the United States which could have a material adverse effect on our financial condition and results of operations.
- The Company's principal asset is an indirect interest in Origination and, accordingly, the Company depends on distributions from Origination to pay its taxes and expenses. Origination's ability to make such distributions may be subject to various limitations and restrictions.
- The Tax Receivable Agreement with Origination, Blocker and the Tax Receivable Recipients (as defined below) requires Blocker to make cash payments to the Tax Receivable Recipients in respect of certain tax benefits to which Blocker may become entitled, and Blocker expects that the payments Blocker will be required to make may be substantial.
- The Company's organizational structure, including the Tax Receivable Agreement, confers certain benefits upon the Tax Receivable Recipients that will not benefit the holders of Subordinate Voting Shares, Multiple Voting Shares or Proportionate Voting Shares to the same extent as it will benefit the Tax Receivable Recipients.
- Payments under the Tax Receivable Agreement to the Tax Receivable Recipients may be accelerated or exceed the benefits Blocker realizes in respect of the tax attributes subject to the Tax Receivable Agreement.
- Blocker will not be reimbursed for any payments made to the Tax Receivable Recipients in the event that any tax benefits are disallowed.

Investors should carefully consider the risk factors set out below and consider all other information contained herein, and in the Company's other public filings, before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business and the oil, natural gas, and NGL business generally.

The risks set out below are grouped into the following categories: (1) Risks Related to the Business; (2) Macroeconomic and Financial Risks; (3) Legal and Regulatory Risks; (4) Risks Related to Ownership of our Subordinate Voting Shares and (5) Certain Tax Risks. Many risks affect more than one category, and the risks are not in the order of significance or probability of occurrence because they have been grouped by categories.

Risks Related to the Business

Any investment in our shares should be considered highly speculative

An investment in the Company should be considered highly speculative due to the nature of the Company's involvement in the acquisition, development, production, and marketing of oil, natural gas, and NGL reserves and production and its current stage of development. Oil and natural gas operations involve many risks which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company, or that the Company will be able to successfully monetize its current reserves.

We are largely dependent on crude oil, natural gas, and NGL pricing, which may affect the value of the Company's assets and its ability to pursue its business objectives

The Company's financial results are largely dependent on the prevailing prices of crude oil, natural gas, and NGL. Crude oil, natural gas, and NGL pricing are subject to fluctuations in supply, demand, market uncertainty and other factors that are beyond the Company's control. This can include but is not limited to: the global and domestic supply of and demand for crude oil, natural gas, and NGL; global and North American economic conditions; the actions of the Organization of Petroleum Exporting Countries ("**OPEC**") or individual producing nations; the Russian invasion of Ukraine; government regulation; political stability; the ability to transport commodities to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; the ongoing impact of COVID-19 and related government mandates on global economic conditions, and weather conditions. In addition, significant growth in crude oil, natural gas, and NGL production in the United States has resulted in pressure on transportation and pipeline capacity which contributes to fluctuations in prices. All of these factors are beyond the Company's control and can result in a high degree of price volatility.

Fluctuations in the price of commodities and associated price differentials affect the value of the Company's assets and the Company's ability to pursue its business objectives. Prolonged periods of low commodity prices and volatility may also affect the Company's ability to meet its financial obligations as they come due. Any substantial and extended decline in the price of crude oil, natural gas, or NGL could have an adverse effect on the Company's reserves, borrowing capacity, revenues, profitability and cash flow and may have a material adverse effect on the Company's business, financial condition, results of operations, prospects and the level of expenditures for the development of crude oil and natural gas reserves. This may include delay or cancellation of existing or future drilling or development partnerships or curtailment in production as the economics of producing from some wells may become impaired.

In addition, bank borrowings available to the Company are, in part, determined by the value of the Company's assets. A sustained material decline in commodity prices from historical average prices could reduce the value of the Company's assets, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid, as well as curtailment of the Company's investment programs.

The Company conducts regular assessments of the carrying amount of its assets in accordance with US GAAP. If crude oil, natural gas, or NGL pricing decline significantly and remain at low levels for an extended period of time, the carrying amount of the Company's assets may be subject to impairment.

Oil, natural gas, and NGL pricing are volatile. Low and volatile commodity prices may adversely affect our business, financial condition, or results of operations and our ability to meet our capital expenditure obligations and financial commitments

When the Company identifies hydrocarbons of sufficient quantity and quality and successfully brings them on stream, it faces a pricing environment which is volatile and subject to a myriad of factors, largely out of the Company's control. Low prices for the Company's expected primary products will have a material effect on the Company's cash flow and profitability and thus re-investment capacity, and hence ultimate growth potential. Low prices also limit access to capital, both equity and debt. The Company in part mitigates the risk of pricing volatility through the use of risk management contracts, such as puts, fixed priced sales, swaps, collars or similar contracts. However, access to such commodity price protection instruments may not be available in future periods, or available only at a cost considered to be uneconomic.

Lower commodity prices may disrupt the production of crude oil, natural gas, and NGL reserves at an acceptable level of profitability

Production of crude oil, natural gas, and NGL reserves at an acceptable level of profitability may not be possible during periods of low commodity prices. The Company will attempt to mitigate this risk by focusing on higher netback opportunities and will act as operator where possible, thus allowing the Company to manage costs, timing, method and marketing of production. Production risk is also addressed by concentrating field activity in regions where infrastructure is or will be readily accessible at an acceptable cost. In periods of low commodity prices, the Company may shut-in production, either temporarily or permanently, if netbacks are sub-economic.

We may not be able to maintain sufficient capital programs

Capital expenditures are designed to accomplish two main objectives, being the generation of short- and medium-term cash flow from development activities, and expansion of future cash flow from the identification of or further development of reserves and opportunities. The Company focuses its activity in core areas, which allows it to leverage its experience and knowledge, and acts as operator wherever possible. The Company may use farm-outs to minimize risk on plays it considers higher risk or where total capital invested exceeds an acceptable level. In addition, the Company may enter into risk management contracts in support of capital programs, and to manage future debt levels. Generally, capital programs are financed from operating cash flows, disciplined use of debt, development partnerships and occasionally, equity. Failure to develop producing wells or to sell production at a reasonable price and thus maintain an acceptable level of cash flow, will result in the exhaustion of available financial resources and will require the Company to seek additional capital which may not be available, or only available on unacceptable terms, or terms highly dilutive to existing shareholders. In addition, credit availability from the Company's bankers is also necessary to support capital programs and any changes to credit arrangements may have an effect on both the size of the Company's future capital programs and the timing of expenditures. As the banking facility available to the Company is based on future cash flows from existing production, falling commodity prices will likely have an effect on borrowing availability.

We may be unable to secure additional funding in the future to cover working capital and investment needs, which could result, among other things, reduced or delayed capital expenditures

The Company's operations are highly capital intensive, and the Company anticipates that it will make substantial capital expenditures for the acquisition, development and production of oil, natural gas, and NGL reserves in the future, including in relation to its assets. The Company may therefore require additional funding in the future to cover working capital and investment needs. Should the Company not be able to obtain such funding on favorable terms, or at all, the Company may, *inter alia*, be forced to reduce or delay capital expenditures, sell assets on unfavorable terms or to restructure or refinance its debt. Failure to obtain funding could also cause the Company to forfeit its interest in certain properties and to miss certain acquisition opportunities. Any of the aforementioned could have a material adverse effect on the Company's business, results of operations, prospects and financial condition.

We may be unable to obtain additional funding in order to carry out our oil, natural gas, and NGL acquisition and development activities

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time-to-time, the Company may require additional financing in order to carry out its oil, natural gas, and NGL acquisition and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil, natural gas, and NGL pricing or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flow from operations and current cash balance is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favorable terms.

Adverse well or reservoir performance could result in reduced corporate volumes and revenues

Changes in productivity in wells and areas developed by the Company could result in termination or limitation of production, or acceleration of decline rates, resulting in reduced overall corporate volumes and revenues. In addition, wells drilled by the Company tend to produce at high initial rates followed by rapid declines until a flattening decline profile emerges. There is a risk that the decline profile which eventually emerges for newly drilled wells is sub-economic.

The Company is exposed to changes in the equity markets, which could result in equity not being available

The Company assesses the sufficiency of its cash flow and borrowing capacity to fund its existing capital budget. Nevertheless, funding is finite and investment must result in production being brought on stream, followed by the generation of cash flow and the identification of proved plus probable reserves. Alpine Summit entered into the credit facility with Goldman Sachs (the "**Goldman Facility**") in late 2020 and the October 2021 Facility, which was later replaced by the Corporate Credit Facility and the ABS Facility, which were put into place in order to provide the Company with additional working capital flexibility.

Although equity is another source of financing, the Company is exposed to changes in the equity markets, which could result in equity not being available, or only available under conditions which are unacceptably dilutive to existing shareholders. The inability of the Company to develop profitable operations, with the consequent exclusion from debt and equity markets, may result in the Company curtailing or suspending operations.

Periods of high field activity can result in shortages of services, products, equipment, or manpower in many or all of the components of our development cycles

Periods of high field activity can result in shortages of services, products, equipment, or manpower in many or all of the components of the development cycle. Increased demand and inflationary pressures may lead to higher land and service costs during peak activity periods. In addition, access to transportation and processing facilities may be difficult or expensive to secure. The Company's competitors include companies with far greater resources, including access to capital and the ability to secure oilfield services at more favorable prices and to build out operations on a scale which lowers the economic threshold for monetization of a resource. The Company competes by maintaining a large inventory of self-generated development locations, by acting as operator where possible, and through facility access. The Company also seeks to carefully manage key supplier relationships. Declines in commodity prices should, in principle, result in lower service costs; however, this may be offset by service providers choosing to retire equipment rather than operate at sub-optimum prices, or ceasing business altogether.

Our crude oil, natural gas, and NGL development and production activities depend on adequate infrastructure and available drilling equipment

Crude oil, natural gas, and NGL development and production activities depend, to one degree or another, on adequate infrastructure and the availability of drilling and related equipment in the particular areas where such activities will be conducted. Reliable roads, bridges, power sources, water supply and disposal facilities are important determinants, which affect capital and operating costs. Unusual or infrequent weather phenomena, sabotage, government or other interference in the maintenance or provision of such infrastructure could adversely affect the operations, financial condition and results of operations. In the past, for example, the Company has had to curtail production to due maintenance issues or equipment damage of our suppliers and marketers. If the Company is unable to obtain, or unable to obtain without undue cost, drilling rigs, equipment, supplies or personnel, its development and production operations could be delayed or adversely affected. Furthermore, pipeline and trucking operations are subject to uncertainty and lack of availability, due to mechanical and/or social issues. Oil, natural gas, and NGLs pipelines and truck transport travel through miles of territory and are subject to the risk of diversion, destruction, or delay. Some transport methods may result in increased levels of risk and could lead to operational delays which could affect the Company's ability to add to its resource base and produce oil and could have a significant impact on its reputation or cash flow. Additionally, some required equipment may be difficult to obtain in the Company's areas of operations, which could hamper or delay operations, and could increase the cost of those operations.

Our production depends in part on adequate gathering and transportation facilities

The marketability of production depends in part on the availability, proximity and capacity of gathering and transportation pipeline facilities and trucks. In South Texas, for example, this has been a particular challenge because of the lack of existing takeaway capacity. These facilities and equipment may be temporarily unavailable to the Company due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions, and may not be available in the future on terms the Company considers acceptable, if at all. If any pipelines, or trucks become unavailable, the Company would, to the extent possible, be required to find a suitable alternative to transport crude oil and condensate, NGLs and natural gas, which could increase the costs and/or reduce the revenues the Company might obtain from the sale of production. Adverse weather, such as rain, mud and ice, have hampered the ability of trucks to get to and from our drilling locations.

Production is also dependent in part on access to third-party facilities and pipelines with the result that production may be reduced by outages, accidents, maintenance programs, pro-rationing and similar interruptions outside of the Company's control. For example, on June 8, 2022, an explosion occurred at the Freeport LNG liquefaction plant on Quintana Island, TX which caused the temporary shutdown of that plant and materially decreased the amount of LNG the U.S. producers, including Alpine Summit, were able to export during the remainder of 2022.

Transportation of natural gas to processing facilities and to market is similarly exposed to the extent that the required capacity is not covered by contract. In addition, contracts for processing or pipeline access are for a fixed term and may not be renewed or may be renewed under more onerous terms. A pipeline shutdown could also have an impact on safety because it would require the use of additional trucksand personnel. In addition, both the cost and availability of pipelinesor trucks to transport production could be adversely impacted by new state or federal regulations relating to transportation of crude oil. Any significant change in market, regulatory or other conditions affecting access to, or the availability of, these facilities and equipment, including due to failure or inability to obtain access to these facilities and equipment on terms acceptable to the Company or at all, could materially and adversely affect business and, in turn, financial condition and results of operations.

Our business and operations could be adversely affected if we lose key personnel

A loss in key personnel of the Company could delay the completion of certain projects or otherwise have a material adverse effect on the Company. Shareholders are dependent on the Company's management and staff in respect of the administration and management of all matters relating to the Company's assets.

Recruiting and retaining qualified personnel is critical to the Company's success. The number of persons skilled in the acquisition and development of oil and natural gas properties is limited and competition for such persons is intense. The Company believes that it will be successful in recruiting excellent personnel to meet its corporate objectives but, as the Company's business activity grows, it may require additional key financial, administrative and technical personnel. Although the Company believes that it will be successful in attracting and retaining qualified personnel, there can be no assurance of such success. In the event that the Company is unable to retain existing qualified personnel and/or attract additional qualified personnel, its ability to grow its business or develop its existing properties could be materially impaired.

Property development projects may not result in the discovery of economic reserves

Alpine Summit's development programs require sophisticated and scarce technical skills as well as capital and access to land and oilfield service equipment. The Company endeavors to minimize the associated risks by ensuring that:

- activity is focused in core regions where internal expertise and experience can be applied;
- prospects are internally generated;
- development drilling is in areas where there is immediate or near-term access to facilities, pipelines and markets or where construction of or access to necessary infrastructure is within the Company's financial capacity; and
- the Company acts as operator where possible which enables the Company to generally control the timing, cost and technical content of its exploration and development programs.

Nevertheless, drilling and completing a well may not result in the discovery of economic reserves, or a well may be rendered uneconomic by commodity price declines or an increasing cost structure. In addition, the Company's investment program has been focused on development of the Giddings Assets and the Hawkville Assets, resulting in asset concentration risk.

Field operations may lead to environmental, health and safety risks

The Company's current and future development and production activities involve the use of heavy equipment and the handling of volatile liquids and gases. Catastrophic events, regardless of cause or responsibility, such as well blowouts, explosions and fires within pipeline, gathering, or facility infrastructure, as well as failure of gathering systems or mechanical equipment, could lead to releases of liquids or gases, spills of contaminants, personal injuries and death, damage to the environment, as well as uncontrolled cost escalation. With support from suitably qualified external parties, the Company has developed and implemented policies and procedures to mitigate environmental, health and safety risks. These policies and procedures include the use of formal corporate policies, emergency response plans, and other policies and procedures reflecting what management considers to be best oilfield practices. These policies and procedures are subject to periodic review. The Company also manages environmental and safety risks by maintaining its operations to a high standard and complying with all state and federal environmental and safety regulations. Nevertheless, application of best practices to field operations serves only to mitigate, not eliminate, risk. The Company maintains industry-specific insurance policies, including environmental damage and control of well, on important owned drilled locations and specific equipment. Although the Company believes its current insurance coverage corresponds to industry standards, there is no guarantee that such coverage will be available in the future, and if it is, at a cost acceptable to the Company, or that existing coverage will necessarily extend to all circumstances or incidents resulting in loss or liability.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition

Markets for future production of crude oil, natural gas, and NGLs are outside the Company's capacity to control or influence and can be affected by events such as weather, climate change, regulation, regional, national and international supply and demand imbalances, facility and pipeline access, geopolitical events, currency fluctuation, introduction of new or termination of existing supply arrangements, as well as downtime due to maintenance or damage, either to owned or third-party facilities and pipelines. The Company will attempt to mitigate these risks as follows:

- Properties are developed in areas where there is access to existing or planned processing and pipeline or other transportation infrastructure.
- The Company will delay drilling or tie-in of new wells or shut-in production if acceptable pricing cannot be realized.

Our future oil, natural gas, and NGL development may involve unprofitable efforts

Oil, natural gas, and NGL development involves a high degree of risk and there is no assurance that expenditures made on development by the Company will result in new discoveries of oil, natural gas, or NGL in commercial quantities. It is difficult to project the costs of implementing a drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the drilling process, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of the Company depends on its ability to find, acquire, develop, and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and natural gas development may involve unprofitable efforts, not only from dry wells, but 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 assure 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 close 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.

In addition, oil and natural gas operations are subject to the risks of development and production of oil, natural gas, and NGL properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow outs, cratering, sour gas releases, fires, spills or leaks. These risks could result in personal injury, loss of life, and environmental or property damage. Any of the aforementioned risks could have a material adverse effect on the Company's future results of operations, liquidity and financial conditions.

We cannot guarantee that the Company's future development efforts will result in the discovery and development of oil and natural gas reserves

The Company's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are realized. A future increase in the Company's reserves will depend not only on the Company's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that the Company's future development efforts will result in the discovery and development of additional commercial accumulations of oil, natural gas, and NGLs.

Project risks may have an impact on our expected revenues

Project delays, should they occur, may delay expected revenues from operations and could also have other negative consequences for the Company. Further, project cost estimates may not be accurate due to several factors, and significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil, natural gas, and NGLs will depend upon numerous factors beyond the Company's control, including: the availability of processing capacity; the availability and proximity of pipeline capacity or other means of transport; the availability of storage capacity; the supply of and demand for oil, natural gas, and NGLs; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labor; and the regulation of the oil and natural gas industry by various levels of government and governmental agencies. Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil, natural gas, and NGLs that it produces. Consequently, any of the aforementioned factors could have a material adverse effect on the Company's business, cash flows, financial position, results of operations or prospects.

As a holding company we are subject to the risks attributable to each of our subsidiaries

Alpine Summit is a holding company and essentially all of its assets are its indirect ownership of Origination. As a result, investors in Alpine Summit will be subject to the risks attributable to Origination and its subsidiaries. As a holding company, Alpine Summit conducts substantially all of its business through Origination and its subsidiaries, which generate substantially all of its revenues. Consequently, Alpine Summit's cash flows and ability to complete current or desirable future enhancement opportunities are dependent on the earnings of Origination and its subsidiaries. The ability of these entities to pay dividends and other distributions will depend on their operating results and will be subject to applicable laws and regulations which require that solvency and capital standards be maintained by such companies and contractual restrictions contained in the instruments governing their debt. In the event of a bankruptcy, liquidation or reorganization of any of the Company's subsidiaries, holders of indebtedness and trade creditors may be entitled to payment of their claims from the assets of those subsidiaries before Alpine Summit, which may have an adverse effect on the business, prospects, result of operation and financial condition of Alpine Summit.

We may not be insured for, or our insurance may be inadequate to protect us against, all risks

The Company's involvement in the development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although the Company has obtained insurance in accordance with industry standards to address such risks, such insurance has exclusions or limitations on liability that may render it insufficient to cover the full extent of such liabilities. In addition, such risks or additional risks may not, in all circumstances be insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company's financial position, results of operations or prospects.

If we are unable to foster necessary working relationships with industry participants, it may impair the Company's ability to grow

The ability of the Company to successfully bid on and acquire additional properties, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements will depend on developing and maintaining effective working relationships with industry participants and on the Company's ability to select and evaluate suitable partners and to consummate transactions in a highly competitive environment. These relationships are subject to change and may impair the Company's ability to grow.

To develop the Company's business, it may enter into strategic and business relationships, which may take the form of joint ventures with other parties or with local government bodies, or contractual arrangements with other oil and natural gas companies, including those that supply equipment and other resources that the Company may use in its business. The Company may not be able to establish these business relationships or, if established, it may not be able to maintain them. In addition, the dynamics of the Company's relationships with strategic partners may require the Company to incur expenses or undertake activities it would not otherwise be inclined to take to fulfill its obligations to these partners or maintain its relationships. If the Company fails to make the cash calls required by its joint venture partners in the joint ventures it does not operate, the Company may be required to forfeit its interests in joint ventures. If the Company's strategic relationships are not established or maintained, its business prospects may be limited, which could diminish its ability to conduct its operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire skilled industry personnel and find and develop reserves in the future

The oil and natural gas industry is highly competitive. The Company actively competes for acquisitions, leases and licenses, skilled industry personnel and capital to finance such activities with a substantial number of other oil and natural gas companies, many of which have significantly greater financial, technical and personnel resources than the Company. The Company's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than the Company's financial, technical or personnel resources permit. The Company's size and financial status may impair its ability to compete for oil and natural gas properties and prospects.

The Company's ability to acquire additional prospects and to find and develop reserves in the future will depend on its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If the Company is unable to compete successfully in these areas in the future, its future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the business practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors the Company cannot control or influence.

We may not be able to keep pace with technological developments in our industry

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete. In such case, the Company's business, financial condition and results of operations could be materially adversely affected. If the Company is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves

Estimates of economically recoverable crude oil, natural gas reserves, and NGLs, and related future net cash flows, are based upon a number of variable factors and assumptions. These include commodity prices, production, future operating, transportation, development and facility as well as decommissioning costs, access to market, and potential changes to the Company's operations or to reserve measurement protocols arising from regulatory or fiscal changes. All of these estimates may vary from actual circumstances, with the result that estimates of recoverable crude oil and natural gas reserves attributable to any property are subject to revision. In future, the Company's actual production, revenues, royalties, transportation, operating expenditures, finding, development, facility and decommissioning costs associated with its reserves may vary from such estimates, and such variances may be material.

We may be exposed to third party credit risk that could have a material adverse effect on the Company's financial results and financial condition

The Company is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, counterparties to financial instruments and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on the Company's financial results and financial condition.

Conservation measures and technological advances could reduce demand for our petroleum products

Fuel reduction regulations, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for crude oil and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Company cannot predict the effect of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flow.

If any of our operations cause damage in the areas in which we operate, the Company's reputation could be negatively affected

Any environmental damage, loss of life, injury or damage to property caused by the Company's operations could damage its reputation in the areas in which the Company operates. Negative sentiment towards the Company could result in a lack of willingness of municipal authorities to grant the necessary licenses or permits for the Company to operate its business and in residents in the areas where the Company is doing business opposing the Company's further operations in the area. If the Company develops a reputation for having an unsafe worksite, it may impact the Company's ability to attract and retain the necessary skilled employees, consultants and contractors to operate its business. Further, the Company's reputation could be affected by actions and activities of other companies operating in the oil and natural gas industry, over which the Company has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Subordinate Voting Shares.

A negative shift in investor or shareholder sentiment of the oil and natural gas industry could adversely affect our business and ability to raise debt and equity capital

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the effect of crude oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and indigenous rights, have affected certain investors' sentiments towards investing in the crude oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can be costly and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the crude oil and natural gas industry, and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Subordinate Voting Shares, even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's assets which may result in an impairment change.

Our operations and financial condition may be impacted by unforeseeable or uncontrollable circumstances

The Company's operations and its financial condition may be affected by uncontrollable, unpredictable and unforeseeable circumstances such as weather patterns, changes in contractual, regulatory or fiscal terms, actions by governments at various levels, both domestic and other, termination of access to third-party pipelines or facilities, actions by industry organizations, local communities, exclusion from certain markets or other undeterminable events.

We may fail in achieving the anticipated benefits of acquisitions and dispositions

The Company may make acquisitions and dispositions of businesses and assets that occur in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses or assets may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management assesses the value and contribution of individual properties and other assets.

We may experience challenges finding, developing, and acquiring petroleum and natural gas reserves on an economic basis

Petroleum and natural gas reserves naturally deplete as they are produced over time. The success of the Company's business is highly dependent on its ability to acquire and/or discover new reserves in a cost-efficient manner. Substantially all of the Company's cash flow is derived from the sale of the oil and natural gas reserves it accumulates and develops. In order to remain financially viable, the Company must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. The Company mitigates this risk by employing a qualified and experienced team of petroleum and natural gas professionals, operating in geological areas in which prospects are well understood by management and by closely monitoring the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Our return on certain assets operated by other companies may depend upon a number of factors that may be outside of our control

The Company has certain farm-in agreements under which other companies may operate some of the assets in which the Company will have or has an interest. The Company will have diminished ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others may therefore depend upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

We may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls, which could have a material adverse impact on our business, operations and prospects

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

We may be unable to obtain all necessary registrations, permits, and authorizations that are required to carry out development at our properties

The operations of the Company require registrations, permits and authorizations from various governmental authorities. There can be no assurance that the Company will be able to obtain all necessary registrations, permits and authorizations that are required to carry out development at its properties. The permitting process in Texas and the United States, particularly at the local level, may take significant time, meaning that development projects have a longer cycle time to completion than they might elsewhere.

Macroeconomic and Financial Risks

Our Debt Facilities (as defined below) contain operating and financial restrictions that may restrict our business and financing activities.

Our Corporate Credit Facility and ABS Facility (collectively, "**Debt Facilities**") contain a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiary;
- redeem our debt;
- make investments;
- incur or guarantee additional indebtedness;
- create or incur certain liens;
- make certain acquisitions and investments;
- enter into agreements that restrict distributions or other payments from our restricted subsidiary to us;
- consolidate, divide, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into swap agreements beyond certain maximum thresholds; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs. Our ability to comply with some of the covenants and restrictions contained in our Debt Facilities may be affected by events beyond our control. If market or other economic conditions deteriorate, or if oil, natural gas, and NGL pricing decline further from their current level or remain volatile for an extended period of time, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our Debt Facilities or any future indebtedness could result in an event of default under our Debt Facilities or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations.

If an event of default under either of our Debt Facilities occurs and remains uncured, the lenders or holders under the applicable Credit Facility:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings or notes outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings or notes; or
- may prevent us from making debt service payments under our other agreements.

The borrowing base under our Corporate Credit Facility is redetermined at least quarterly, based in part on assumptions of the administrative agent with respect to, among other things, crude oil, natural gas, and NGL pricing. A negative adjustment to the borrowing base could occur if crude oil, natural gas, or NGL prices used by the lenders are significantly lower than those used in the last redetermination, including as result of a decline in commodity prices or an expectation that reduced prices will continue. As of December 31, 2022, we had $41,500,000 outstanding under our Corporate Credit Facility. In the event that the amount outstanding under our Corporate Credit Facility exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. In addition, the portion of our borrowing base made available to us for borrowing is subject to the terms and covenants of our Corporate Credit Facility, including compliance with the ratios and other financial covenants of such facility.

Our obligations under the Corporate Credit Facility are collateralized by first priority liens and security interests on substantially all of our assets excluding those included in the ABS Facility, including mortgage liens on oil and natural gas properties having at least 90% of the PV-9 (determined using commodity price assumptions by the administrative agent of the Corporate Credit Facility) of the borrowing base properties (with respect to the Corporate Credit Facility). If we are unable to repay our indebtedness under the Corporate Credit Facility (including any amount of borrowings in excess of the borrowing base resulting from a redetermination of our Corporate Credit Facility), the lenders could seek to foreclose. Our obligations under the ABS Facility are collateralized by first priority liens and security interests on a discrete set of wells that have been conveyed to a subsidiary that issued the ABS Facility notes (the "**Issuer**"). If the Issuer is unable to repay the indebtedness under the ABS Facility, the noteholders could seek to foreclose against the Issuer.

Global market conditions can impact the prices for crude oil, natural gas, and NGLs

Market conditions which include global crude oil, natural gas, and NGL supply and demand and global events including the Russian invasion of Ukraine; actions taken by OPEC, Russia's withdrawal from OPEC, sanctions against Russia, Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, isolationist and punitive trade policies, shale production in the United States, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, the outbreak of COVID-19 and the price war between Saudi Arabia and Russia have caused significant volatility in commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks, including attacks on crude oil infrastructure in crude oil producing nations, in the United States or other countries could adversely affect the economies of the United States and other countries. These events and conditions may cause a significant reduction in the valuation of crude oil and natural gas companies and a decrease in confidence in the future of the crude oil and natural gas industry.

The war in Ukraine and Russia may continue to have a material adverse impact on us and our subsidiaries.

On February 24, 2022, the President of Russia, Vladimir Putin, announced a military invasion of Ukraine. In response, countries worldwide, including the United States, have imposed sanctions against Russia on certain businesses and individuals, including, but not limited to, those in the banking, import and export sectors. This invasion has led, is currently leading, and for an unknown period of time will continue to lead to disruptions in local, regional, national, and global markets and economies affected thereby. These disruptions caused by the invasion have included, and may continue to include, political, social, and economic disruptions and uncertainties and material increases in certain commodity prices that may affect our business operations or the business operations of our subsidiaries.

The implementation of risk management instruments may expose us to certain risks and there can be no assurance that these instruments will be available or continue to be available on commercially reasonable terms

The Company may enter into risk management instruments in the form of swaps, puts, calls, and similar instruments to secure revenue or offset the risk of revenue losses related to changes in commodity prices, carbon prices, interest rates and related global macroeconomic events. However, such arrangements may be expensive and there can be no assurance that these instruments will be available or continue to be available on commercially reasonable terms. In addition, implementing risk management instruments itself carries certain risks, including expenses associated with termination or close-out of treasury transactions under hedging agreements and the risk that the Company could incur losses should it fail to anticipate movements in the underlying referenced futures contract. The Company may also be required to provide cash collateral under its hedging arrangements, which the Company may be unable to provide or which could affect the liquidity of the Company. There is also the risk that the Company will be obliged to make payments under swap arrangements, even in a scenario where its production has decreased or ceased, potentially creating cash obligations which the Company is unable to settle. Further, certain types of hedging arrangements, if entered into by the Company, may also involve a risk of not realizing potential gains if the Company should fail to anticipate movements in the underlying referenced futures contract.

The discontinuation of LIBOR may adversely affect the value of the cost of our borrowings under the ABS Facility

National and international regulators and law enforcement agencies have conducted investigations into a number of rates or indices that are deemed to be "reference rates." Actions by such regulators and law enforcement agencies may result in changes to the manner in which certain reference rates are determined, their discontinuance, or the establishment of alternative reference rates. In particular, on July 27, 2017, the Chief Executive of the U.K. Financial Conduct Authority (the "**FCA**"), which regulates LIBOR, announced that the FCA will no longer persuade or compel banks to submit rates for the calculation of LIBOR after 2021. As of the date of this Annual Report, USD LIBOR is available in five settings (overnight, one-month, three-month, six-month and 12-month). The ICE Benchmark Administration ("**IBA**") has stated that it will cease to publish all remaining USD LIBOR settings immediately following their publication on June 30, 2023, absent subsequent action by the relevant authorities. As of January 1, 2022, all non-USD LIBOR reference rates in all settings ceased to be published. There can be no assurance that non-USD synthetic LIBOR or USD LIBOR will remain available in the future.

The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee (the "**ARRC**"), a steering committee comprised of large U.S. financial institutions, has identified the Secured Overnight Financing Rate ("**SOFR**") as its preferred alternative rate for LIBOR. On December 6, 2021, the ARRC released a statement selecting and recommending forms of SOFR, along with associated spread adjustments and conforming changes, to replace references to 1-week and 2-month USD LIBOR. We expect that a substantial portion of our future floating rate investments will be linked to SOFR. At this time, it is not possible to predict the effect of the transition to SOFR. Although there have been an increasing number of issuances utilizing SOFR or the Sterling Over Night Index Average ("**SONIA**") (the GBP-LIBOR nominated replacement alternative reference rate that is based on transactions), it is unknown whether SOFR or any other alternative reference rates will attain market acceptance as replacements for LIBOR.

Given the inherent differences between LIBOR and SOFR, or any other alternative reference rates that may be established, the transition from LIBOR may disrupt the overall financial markets and adversely affect the cost of our borrowings under the ABS Facility. In addition, changes or reforms to the determination or supervision of LIBOR may result in a sudden or prolonged increase or decrease in reported LIBOR, which could have an adverse impact on the market for LIBOR based securities, including the value and/ The transition from LIBOR to SOFR or other alternative reference rates may also introduce operational risks in our accounting, financial reporting, loan servicing, liability management and other aspects of our business.

Our business, operations, and financial conditions may be adversely affected by the COVID-19 pandemic or other similar pandemics

The Company's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China; on January 30, 2020, the World Health Organization ("**WHO**") declared the outbreak a global health emergency; and on March 11, 2020 the WHO declared the outbreak of COVID-19 a global pandemic. The outbreak spread exponentially throughout the world and despite the development and deployment of vaccines, infections have persisted with numerous variants that have since emerged. The spread of COVID-19 has led companies and various jurisdictions to impose restrictions such as quarantines, business closures and domestic and international travel restrictions. The occasion and duration of the business disruptions internationally and related financial effect cannot be reasonably estimated at this time. Similarly, the Company cannot estimate whether or to what extent this pandemic and the potential financial effect may extend beyond what has already been experienced.

Such public health crises can result in volatility and disruptions in the supply, demand, and pricing for crude oil, natural gas, and NGLs, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, crude oil prices significantly weakened in 2020 in response to the outbreak of COVID-19. The risks to the Company of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations affected by an outbreak. This could include the Company's wells and facilities and/or third-party facilities and pipelines used by the Company.

At this point, the extent to which COVID-19 may continue to affect the Company is uncertain; however, it is possible that the ongoing COVID-19 pandemic may have a material adverse effect in the future on the Company's business, results of operations and financial condition. If subsequent waves or additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, there may be further adverse impacts on the economy, commodity prices, and the Company's operations.

We believe that in addition to the impacts described above, other impacts included or could in the future include, but are not limited to:

- Structural shift in the global economy and its demand for oil, natural gas, and NGLs as a result of changes in the way people work, travel and interact, or in connection with a global or regional recession or depression;
- Infections and quarantining of our employees and the personnel of other third parties in areas in which we operate;

- Our insurance policies may not cover losses associated with pandemics or similar global health threats;
- Litigation risk and possible loss contingencies related to a pandemic and its impact, including with respect to commercial contracts, employment matters, personal injury and insurance arrangements; and
- Cybersecurity incidents, as our reliance on digital technologies increases, those digital technologies may become more vulnerable and experience a higher rate of cybersecurity attacks, intrusions or incidents in the current environment of remote connectivity, as well as increased geopolitical conflicts and tensions.

Legal and Regulatory Risks

Our operations can be substantially affected by changes in government regulations and policies

In the United States the energy industry is subject to scrutiny, frequently hostile, by political and environmental groups. This may lead to increased regulation and increased compliance costs. In particular, there is a risk that existing income tax rates could be increased, rules and regulations around well licensing or surface access could be changed, horizontal drilling and hydraulic fracturing could be subject to increased oversight or regulation.

We are subject to stringent federal and state laws and regulations related to labor and occupational health and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities

The Company is subject to labor and health and safety laws and regulations, at a national and state level in the United States, that govern, among other things, the relationship between the Company and its employees and the health and safety of the Company's employees. For example, the Company is required to adopt certain measures to safeguard the health and safety of its employees, as well as third parties, in its work locations. In the event that compliance by the Company with such requirements is reviewed by the applicable authorities and a decision that the Company violated any labor or health and safety laws, results from such review, the Company may be exposed to penalties and sanctions, including the payment of fines and, depending on the level of severity of the infraction, exposed to the closure of its work locations and/or stoppage of its operations and the cancellation or suspension of governmental registrations, permits, or authorizations, any one of which may result in interruption or discontinuity of activities in the Company's facilities, and materially and adversely affect the Company.

We are subject to restrictions and costs related to water and waste disposal

The Company may be subject to regulation that restricts our ability to discharge water produced as part of production operations. Productive zones frequently contain water that must be removed in order for the oil and natural gas to produce, and ability to remove and dispose of sufficient quantities of water from the various zones will determine whether the Company can produce oil, natural gas, and NGLs in commercial quantities. The produced water must be transported from the leasehold and/or injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from wells may affect the ability to produce wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce profitability. Where water produced from projects fails to meet the quality requirements of applicable regulatory agencies, wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or the Company is unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, the Company may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment.

The costs to dispose of this produced water may increase if any of the following occur:

- the Company cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

The disposal of fluids gathered from oil, natural gas, and NGLs producing operations in underground disposal wells has been pointed to by some groups and regulators as a potential cause of increased induced seismic events in certain areas of the country, particularly in Oklahoma, Texas, Colorado, Kansas, New Mexico and Arkansas. Several states have adopted or are considering adopting laws and regulations that may restrict or otherwise prohibit oilfield fluid disposal in certain areas or underground disposal wells, and state agencies implementing those requirements may issue orders directing certain wells in areas where seismic incidents have occurred to restrict or suspend disposal well operations or impose standards related to disposal well construction and monitoring. While the Company cannot predict the ultimate outcome of these actions, any action that temporarily or permanently restricts the availability of disposal capacity for produced water or other oilfield fluids may increase costs or have other adverse impacts on operations.

We are subject to stringent federal, state, and local laws and regulations related to environmental issues that could adversely affect the cost, manner, or feasibility of conducting our operations or expose us to significant liabilities

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 international conventions and national, state and local laws and regulations. As an owner, licensee, and/or operator of oil and natural gas properties in the United States, the Company is subject to various national, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Environmental laws and regulations in the United States impose substantial restrictions on, among other things, the use of natural resources, interference with the natural environment, the location of facilities, the handling and storage of hazardous materials such as hydrocarbons, the use of radioactive material, the disposal of waste, and the emission of noise and other activities. These laws and regulations may, among other things: (a) impose liability on the owner or lessee under an oil and natural gas lease for the cost of property damage, oil spills, discharge of hazardous materials, remediation and clean-up resulting from operations; (b) subject the owner or lessee to liability for pollution damages and other environmental or natural resource damages; and (c) require suspension or cessation of operations in affected areas.

Environmental protection legislation in the United States is evolving in a manner that has and is expected to continue to result in stricter standards and enforcement, larger fines, liabilities and sanctions, and potentially increased capital expenditures and operating costs. To mitigate potential environmental liabilities, the Company, in addition to implementing policies and procedures designed to prevent an accidental spill or discharge, maintains insurance at industry standards.

If existing environmental regulatory requirements or enforcement policies change or new regulatory or enforcement initiatives are developed and implemented in the future, the Company may be required to make significant, unanticipated capital and operating expenditures with respect to its continued operations. Moreover, these risks are likely to be enhanced with the current presidential administration and Democrats controlling Congress. Examples of recent environmental regulations include the following:

•*Ground-Level Ozone Standards*. In 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("**NAAQS**") for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. Since that time, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local, and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of the Company's equipment, result in longer permitting timelines, and significantly increase the Company's capital expenditures and operating costs arising from the program's operations.

• *EPA Review of Drilling Waste Classification*. Drilling, fluids, produced water and most of the other wastes associated with the exploration, development and production of oil, natural gas, or NGLs, if properly handled, are currently exempt from regulation as hazardous waste under the RCRA and instead, are regulated under RCRA's less stringent non-hazardous waste provisions. However, it is possible that certain oil, natural gas, and NGL drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the Company's costs to manage and dispose of generated wastes, which could have a material adverse effect on the industry as well as on the Company's business.

• *Federal Jurisdiction over Waters of the United States*. In 2015, the EPA and U.S. Army Corps of Engineers ("**Corps**") under the Obama Administration released a final rule outlining federal jurisdictional reach under the Clean Water Act, over waters of the United States, including wetlands. However, the EPA rescinded this rule in 2019 and promulgated the Navigable Waters Protection Rule in 2020. The Navigable Waters Protection Rule defined what waters qualify as navigable waters of the United States and are under Clean Water Act jurisdiction. This new rule has generally been viewed as narrowing the scope of waters of the United States as compared to the 2015 rule, but litigation in multiple federal district courts is currently challenging the rescission of the 2015 rule and the promulgation of the Navigable Waters Protection Rule. In June 2021, the Biden Administration announced plans to develop its own definition for jurisdictional waters, and in August 2021, a federal judge for the U.S. District Court for the District of Arizona issued an order striking down the Navigable Water Protection Rule. On December 7, 2021, the U.S. Environmental Protection Agency and the Department of the Army announced a proposed rule to revise the definition of "waters of the United States," which would return to the 2015 definition of "waters of the United States," updated to reflect consideration of Supreme Court decisions. On January 24, 2022, the Supreme Court agreed to consider the scope of the Clean Water Act again in Sackett v. EPA. To the extent that a revised rule or Supreme Court decision expands the scope of the Clean Water Act's jurisdiction in areas where the Company conducts operations, the Company could incur increased costs and restrictions, delays or cancellations in permitting or projects, which developments could expose it to significant costs and liabilities.

Additionally, the federal Occupational Safety and Health Act and analogous state occupational safety and health laws require employers to organize information about materials, some of which may be hazardous or toxic, that are used, released or produced in the Company's operations. Moreover, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in the Company's operations and that this information be provided to employees as well as certain persons employed by OSHA or its state counterparts.

The discharge of oil, natural gas, NGLs, or other pollutants into the air, soil, or water may give rise to liabilities to third parties and may require the Company to incur costs to remedy such discharge in the event that they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit.

The Company's oil, natural gas, and NGL operations include drilling, well completions and tie-ins, production, facility operation, distribution, pricing, marketing and transportation and are subject to compliance with federal, state and local laws and regulations controlling the discharge of pollutants into the environment or otherwise relating to the protection of the environment. Regulations and laws impose restrictions on emissions, spills and releases of various substances used in oil and natural gas industry operations, requirements for waste handling and storage, habitat protection and the operation, maintenance, abandonment and reclamation of facilities, pipelines and wells. Changes to environmental regulations could delay or prevent planned activity, affect current and forecast production levels and increase the cost of production and/or development capital expenditures.

Although the Company believes that it is in material compliance with current applicable environmental regulations, changing government regulations may have an adverse effect on the Company. The Company's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. The Company also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation.

No assurance can be given that environmental laws will not result in a curtailment of production, a material increase in the costs of production or the costs of development activities, or otherwise adversely affect the Company's financial condition, capital expenditures, results of operations, competitive position or prospects. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential future effects on Alpine Summit.

Climate change, environmental, social and governance and sustainability initiatives may result in regulatory or structural industry changes and/or could result in increased operating costs and reduced demand for the oil, natural gas, and NGLs that we produce while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects

Climate change, environmental, social and governance ("**ESG**") and sustainability are a growing global movement. Continuing political and social attention to these issues has resulted in both existing and pending international agreements and national, regional and local legislation, regulatory measures, reporting obligations and policy changes. Also, there is increasing societal pressure in some of the areas where we operate, to limit greenhouse gas emissions as well as other global initiatives. These agreements and measures, including the Paris Climate Accord, may require, or could result in future legislation, regulatory measures or policy changes that would require significant equipment modifications, operational changes, taxes, or purchases of emission credits to reduce emission of greenhouse gases from our operations or those of our customers, which may result in substantial capital expenditures and compliance, operating, maintenance and remediation costs. As a result of heightened public awareness and attention to these issues as well as continued political and regulatory initiatives to reduce the reliance upon oil, natural gas, and NGLs, demand for hydrocarbons may be reduced, which could have an adverse effect on our business, financial condition, and results of operations. The imposition and enforcement of stringent greenhouse gas emissions reduction requirements could severely and adversely impact the oil and natural gas industry and therefore significantly reduce the value of our business.

Certain financial institutions, institutional investors and other sources of capital have begun to limit or eliminate their investment in financing of conventional energy-related activities due to concerns about climate change, which could make it more difficult for our customers and for us to finance our respective businesses. Increasing attention to climate change, ESG and sustainability has resulted in governmental investigations, and public and private litigation, which could increase our costs or otherwise adversely affect our business or results of operations.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other companies or industries, which could have a negative impact on the price of our securities and our access to and costs of capital.

Any or all of these ESG and sustainability initiatives may result in significant operational changes and expenditures, reduced demand for our products and services, and could materially adversely affect our business, financial condition, results of operations, stock price or access to capital markets.

We may become involved in, named as a party to, or be the subject of, various legal proceedings

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, proceedings related to personal injuries, property damage, property tax, provision of services, leases, land rights, the environment and/or contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations.

Risks Related to Ownership of our Common Stock

The Board of Directors may modify or revoke our dividend policy at any time at its discretion

The declaration and payment of future dividends (and the amount thereof) is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, the financial condition of the Company, production levels, results of operations, capital expenditure requirements, working capital requirements, debt service requirements, operating costs, interest rates, contractual restrictions, the Company's hedging activities or programs, available investment opportunities, the Company's business plan, strategies and objectives, the satisfaction of the solvency and liquidity tests imposed by the BCBCA for the declaration and payment of dividends and other factors that the Board may deem relevant. Depending on these and various other factors, many of which are beyond the control of the Company, the dividend policy of the Company may vary from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

Pursuant to the BCBCA, the Company may not declare or pay a dividend if there are reasonable grounds for believing that: (i) the Company is, or would after the payment be, unable to pay its liabilities as they become due; or (ii) the realizable value of its assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares.

Dividends may be reduced or suspended during periods of lower cash flow from operations. The timing and amount of the Company's capital expenditures, and the ability of the Company to repay or refinance debt as it becomes due, directly affect the amount of cash dividends that may be declared by the Board. Future acquisitions, expansions of the Company's assets, and other capital expenditures and the repayment or refinancing of debt as it becomes due may be financed from sources such as cash flows from operations, the issuance of additional shares or other securities of the Company, and borrowings. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made. There can be no assurance that sufficient capital will be available on terms acceptable to the Company, or at all, to make additional investments, fund future expansions or make other required capital expenditures. To the extent that external sources of capital, including the issuance of additional shares or other securities or the availability of credit facilities, become limited or unavailable on favorable terms or at all due to credit market conditions or otherwise, the ability of the Company to make the necessary capital investments to maintain or expand its operations, to repay debt and to invest in assets, as the case may be, may be impaired. To the extent the Company is required to use cash flows from operations to finance capital expenditures or acquisitions or to repay debt as it becomes due, the cash available for dividends may be reduced and the level of dividends declared may be reduced or suspended entirely.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amounts of dividends, if any, it may pay in the future. If the Company pays dividends, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn.

The market value of the Company's securities may deteriorate if dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes.

Our principal shareholder, executive officers, and directors have the ability to control or significantly influence all matters submitted to the Company's shareholders for approval

Our largest shareholder holds approximately 31.9% of the voting rights of the Company as of March 27, 2023. In addition, management and the Board own or control approximately 17.7% of the Subordinate Voting Shares as of March 27, 2023. If acting together, such holders would be able to significantly influence all matters requiring shareholder approval, including without limitation, the election of directors.

Conflicts of interest could arise in the future between us, on the one hand, and certain of our directors and officers

Directors and officers of the Company may also be directors and officers of other oil and natural gas companies involved in oil and natural gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Company and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the BCBCA.

Any additional capital raised by the Company through the sale of equity or convertible securities may dilute your ownership in the Company

The Company may issue additional securities in the future, which may dilute a shareholder's holdings in the Company. The Company's articles permit the issuance of an unlimited number of Subordinate Voting Shares, Multiple Voting Shares and Proportionate Voting Shares, and shareholders will have no pre-emptive rights in connection with such further issuances. Also, additional shares may be issued by the Company in a number of circumstances, including on the exercise of warrants that may be issued by the Company, on the exercise of convertible securities under the Company's equity incentive plans and in connection with the put right granted by Origination in respect of any of the Company's development partnerships.

We are a smaller reporting company and we cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our Subordinate Voting Shares less attractive to investors

We are currently a "smaller reporting company" as defined by Rule 12b-2 of the Exchange Act. As a "smaller reporting company," we are subject to reduced disclosure obligations in our SEC filings compared to other issuers, including, among other things, an exemption from the requirement to present five years of selected financial data, being required to provide only two years of audited financial statements in annual reports and being subject to simplified executive compensation disclosures. Until such time as we cease to be a "smaller reporting company," such reduced disclosure in our SEC filings may make it harder for investors to analyze our operating results and financial prospects. If some investors find our common stock less attractive as a result of any choices to reduce disclosure we may make, there may be a less active trading market for our common stock and our stock price may be more volatile.

We are currently an "Emerging Growth Company" under United States Securities Laws

We are an "emerging growth company" as defined in section 3(a) of the Exchange Act (as amended by the JOBS Act), and will continue to qualify as an emerging growth company until the earliest to occur of: (a) the last day of the fiscal year during which we have total annual gross revenues of US$1.235 billion (as such amount is indexed for inflation every five years by the SEC) or more; (b) the last day of our fiscal year following the fifth anniversary of the date of the first sale of common equity securities pursuant to an effective registration statement under the Securities Act; (c) the date on which we have, during the previous three-year period, issued more than US$1 billion in non-convertible debt; and (d) the date on which we are deemed to be a "large accelerated filer", as defined in Rule 12b-2 under the Exchange Act. We will qualify as a large accelerated filer (and would cease to be an emerging growth company) at such time when on the last business day of our second fiscal quarter of such year the aggregate worldwide market value of our common equity held by non-affiliates is US$700 million or more.

For so long as we remain an emerging growth company, we are permitted to, and intend to, rely upon exemptions from certain disclosure requirements that are applicable to other public companies that are not emerging growth companies. These exemptions include not being required to comply with the auditor attestation requirements of Section 404. We cannot predict whether investors will find our securities less attractive because we rely upon certain of these exemptions. If some investors find the securities less attractive as a result, there may be a less active trading market for our securities and the price of our securities may be more volatile. On the other hand, if we no longer qualify as an emerging growth company, we would be required to divert additional management time and attention from development and other business activities and incur increased legal and financial costs to comply with the additional associated reporting requirements, which could negatively impact our business, financial condition and results of operations.

Certain Tax Risks

The following is a discussion of certain material federal income tax risks associated with the acquisition and ownership of Subordinate Voting Shares. This Annual Report does not discuss risks associated with any applicable state, provincial, local or foreign tax laws. The tax related information in this Annual Report does not constitute tax advice and is for informational purposes only. For advice on tax laws applicable to a shareholder's individual tax situation, shareholders should seek the advice of their tax advisors. Each prospective shareholder is urged to review this Annual Report in its entirety and to consult his, her or its own tax advisors with respect to the federal, state, provincial, local and foreign tax consequences arising in connection with the acquisition and ownership of Subordinate Voting Shares.

Tax Classification of the Company

Although the Company is and expects to continue to be a Canadian corporation, the Company should be treated as a United States corporation for United States federal income tax purposes under Section 7874 of the U.S. Internal Revenue Code of 1986, as amended ("**Code**") and should be subject to United States federal income tax on its worldwide income. However, for Canadian tax purposes and regardless of any application of Section 7874 of the Code, the Company will be treated as being resident in Canada under the *Income Tax Act* (Canada) ("**Tax Act**") and be subject to Canadian federal income tax on its worldwide income. As a result, the Company is anticipated to be subject to taxation both in Canada and the United States which could have a material adverse effect on its financial condition and results of operations.

Dividends received by shareholders who are residents of Canada for purposes of the Tax Act generally must be included in the shareholder's income for Canadian tax purposes and will also be subject to U.S. withholding tax. Any such dividends may not qualify for a reduced rate of U.S. withholding tax under the Canada-United States income tax treaty. In addition, a foreign tax credit or a deduction under the Tax Act in respect of any U.S. withholding tax may not be available for such Canadian shareholders.

Dividends received by U.S. shareholders will not be subject to U.S. withholding tax, but will be subject to Canadian withholding tax. For U.S. federal income tax purposes, a U.S. shareholder may elect for any taxable year to receive either a credit or a deduction for all foreign income taxes paid to the shareholder during the year. Dividends paid by the Company will be characterized as U.S. source income for purposes of the foreign tax credit rules under the Code. Accordingly, U.S. shareholders generally will not be able to claim a credit for any Canadian tax withheld unless, depending on the circumstances, they have an excess foreign tax credit limitation due to other foreign source income that is subject to a low or zero rate of foreign tax. In addition, Treasury Regulations that apply to taxes paid or accrued impose additional requirements for Canadian withholding taxes to be eligible for a foreign tax credit, and there can be no assurance that those requirements will be satisfied. Subject to certain limitations, a U.S. shareholder should be able to claim a deduction for the U.S. shareholder's Canadian tax paid, provided that the U.S. shareholder has not elected to credit other foreign taxes during the same taxable year.

Dividends received by shareholders that are neither Canadian nor U.S. shareholders will be subject to both U.S. and Canadian withholding tax. These dividends may not qualify for a reduced rate of U.S. or Canadian withholding tax under any income tax treaty otherwise applicable to a shareholder of the Company, subject to examination of the relevant treaty.

Because the Subordinate Voting Shares will be treated as shares of a U.S. domestic corporation, the U.S. gift, estate and generation-skipping transfer tax rules generally apply to a non-U.S. shareholder of Subordinate Voting Shares.

As a U.S. domestic corporation for U.S. federal income tax purposes, the taxation of the Company's non-U.S. shareholders upon a disposition of Subordinate Voting Shares generally depends on whether the Company is classified as a United States real property holding corporation (a "**USRPHC**") under the Code. The Company expects that it may be classified as a USRPHC for the foreseeable future. Accordingly, it is expected that non-U.S. shareholders will generally be subject to U.S. federal income tax at graduated tax rates as if the gain or loss realized on any disposition of Subordinate Voting Shares was effectively connected with the conduct of a U.S. trade or business, unless the Subordinate Voting Shares were "regularly traded on an established securities market" within the meaning of Section 897 of the Code during such period under the rules set forth in Treasury Regulations, in which case non-U.S. shareholders whose holdings (actually and constructively) at all times during the shorter of the five-year period ending on the date of disposition and such non-U.S. shareholder's holding period for the Subordinate Voting Shares (if shorter) constituted 5% or less of the Company's Subordinate Voting Shares would generally not be subject to such U.S. federal income tax. Alpine's Subordinate Voting Shares are currently listed on the TSXV and traded on the NASDAQ. There can be no assurance that the Subordinate Voting Shares will satisfy such regularly traded exception at any particular point in the future.

Changes in tax laws and the recently enacted Inflation Reduction Act of 2022 may affect the Company and its shareholders

There can be no assurance that the Canadian and U.S. federal income tax treatment of the Company or an investment in the Company will not be modified, prospectively or retroactively, by legislative, judicial or administrative action, in a manner adverse to the Company or its shareholders.

Changes to U.S. tax laws (which changes may have retroactive application) could adversely affect the Company or its shareholders. In recent years, many changes to U.S. federal income tax laws have been proposed and made, and additional changes to U.S. federal income tax laws are likely to continue to occur in the future.

The U.S. Congress is currently considering numerous items of legislation which may be enacted prospectively or with retroactive effect, which legislation could adversely impact the Company's financial performance and the value of the Subordinate Voting Shares. Additionally, states in which we operate or own assets may impose new or increased taxes. If enacted, most of the proposals would be effective for current or later years. The proposed legislation remains subject to change, and its impact on the Company and holders of Subordinate Voting Shares is uncertain.

In addition, the Inflation Reduction Act of 2022 was recently signed into law and includes provisions that will impact the U.S. federal income taxation of corporations. Among other items, this legislation includes provisions that will impose a minimum tax on the book income of certain large corporations and an excise tax on certain corporate stock repurchases that would be imposed on the corporation repurchasing such stock. Because the Company should be treated as a United States corporation for United States federal income tax purposes under Section 7874 of the Code, it is anticipated that the Company will likely be subject to the excise tax on certain corporate stock repurchases should it affect any such repurchase transactions. However, it remains unclear how this legislation will be implemented by the U.S. Department of the Treasury and we cannot predict how this legislation or any future changes in tax laws might affect the Company or holders of Subordinate Voting Shares.

Future federal, state or local legislation also may impose new or increased taxes or fees on oil, natural gas, and NGL extraction or production

Future changes in U.S. federal income tax laws, or the introduction of a carbon tax, as well as any similar changes in state law, could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations, and cash flows. Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil, natural gas, and NGL extraction or production. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices the Company receives for its oil, natural gas, or NGLs.

Tax Risks Relating to the Company's Organizational Structure

The Company's principal asset is an indirect interest in Origination and, accordingly, the Company depends on distributions from Origination to pay its taxes and expenses. Origination's ability to make such distributions may be subject to various limitations and restrictions

The Company is a holding company and has no material assets other than its indirect ownership of Origination units. As such, the Company has no independent means of generating revenue or cash flow. Moreover, the Company's ability to pay its taxes and operating expenses or declare and pay dividends in the future, if any, will be dependent upon the financial results and cash flows of Origination and its subsidiaries and distributions it receives indirectly from Origination. There can be no assurance that Origination and its subsidiaries will generate sufficient cash flow to distribute funds to the Company or that applicable state law and contractual restrictions will permit such distributions.

Origination will continue to be treated as a partnership for U.S. federal income tax purposes and, as such, will generally not be subject to entity-level U.S. federal income tax. Instead, taxable income will be allocated to the holders of Origination Class A Voting Units and Class B Non-Voting Units. Accordingly, holders of Origination Class A Voting Units and Class B Non-Voting Units will incur income taxes on their allocable share of any net taxable income of Origination. Origination is obligated to make tax distributions to holders of Origination Class A Voting Units and Class B Non-Voting Units. Blocker intends, as its manager, to cause Origination to make cash distributions to the owners of Origination Class A Voting Units and Class B Non-Voting Units in an amount sufficient to fund their tax obligations in respect of taxable income allocated to them, and make cash payments to cover the operating expenses of Blocker and the Company, including payments under the Tax Receivable Agreement (as defined below). However, Origination's ability to make such distributions and payments may be subject to various limitations and restrictions, such as restrictions on distributions and payments that would either violate any contract or agreement to which Origination is then a party, including debt agreements, or any applicable law, or that would have the effect of rendering Origination insolvent. If the Company does not have sufficient funds to pay tax or other liabilities or to fund its operations, it may have to borrow funds, which could materially adversely affect its liquidity and financial condition and subject it to various restrictions imposed by any such lenders. In addition, if Origination does not have sufficient funds to make distributions, the Company's ability to declare and pay cash dividends will also be restricted or impaired.

The Tax Receivable Agreement with Origination, Blocker and the Tax Receivable Recipients (as defined below) requires Blocker to make cash payments to the Tax Receivable Recipients in respect of certain tax benefits to which Blocker may become entitled, and Blocker expects that the payments Blocker will be required to make may be substantial

Blocker is a party to the Tax Receivable Agreement with Origination, the Initial Holder and certain executive employees (such agreement, the "**Tax Receivable Agreement**" and the Initial Holder and executive employees party to the Tax Receivable Agreement, the "**Tax Receivable Recipients**"). Under the Tax Receivable Agreement, Blocker will be required to make cash payments to the Tax Receivable Recipients equal to 85% of the tax benefits, if any, that Blocker actually realizes, or in certain circumstances is deemed to realize, as a result of: (i) the increases in its share of the tax basis of assets of Origination resulting from any redemptions or exchanges of Class B Non-Voting Units**,** and (ii) certain other tax benefits related to Blocker making payments under the Tax Receivable Agreement. Although the actual timing and amount of any payments that Blocker makes to the Tax Receivable Recipients under the Tax Receivable Agreement will vary, it expects those payments may be significant. Any payments made by Blocker to the Tax Receivable Recipients under the Tax Receivable Agreement may generally reduce the amount of overall cash flow that might have otherwise been available to it. Furthermore, Blocker's future obligation to make payments under the Tax Receivable Agreement could make the Company a less attractive target for an acquisition.

The actual amount and timing of any payments under the Tax Receivable Agreement will vary depending upon a number of factors, including the timing of redemptions and exchanges by the holders of Class B Non-Voting Units, the amount of gain recognized by such holders of Class B Non-Voting Units, the amount and timing of the taxable income Blocker generates in the future, and the federal tax rates then applicable.

The Company's organizational structure, including the Tax Receivable Agreement, confers certain benefits upon the Tax Receivable Recipients that will not benefit the holders of Subordinate Voting Shares, Multiple Voting Shares or Proportionate Voting Shares to the same extent as it will benefit the Tax Receivable Recipients

The Company's organizational structure, including the Tax Receivable Agreement, confers certain benefits upon the Tax Receivable Recipients that will not benefit the holders of Subordinate Voting Shares, Multiple Voting Shares or Proportionate Voting Shares to the same extent as it will benefit the Tax Receivable Recipients. Origination will be a party to the Tax Receivable Agreement with Blocker, and the Tax Receivable Recipients and it will provide for the payment by Blocker to the Tax Receivable Recipients of 85% of the amount of tax benefits, if any, that it actually realizes, or in some circumstances is deemed to realize, as a result of (i) the increases in the tax basis of assets of Origination resulting from any redemptions or exchanges of Class B Non-Voting Units from the holders thereof as described under Article XI of the A&R LLC Agreement, and (ii) certain other tax benefits related to Blocker making payments under the Tax Receivable Agreement.

In certain cases, payments under the Tax Receivable Agreement to the Tax Receivable Recipients may be accelerated or significantly exceed the actual benefits Blocker realizes in respect of the tax attributes subject to the Tax Receivable Agreement

The Tax Receivable Agreement provides that upon certain mergers, asset sales, other forms of business combinations or other changes of control or if, at any time, Blocker elects an early termination of the Tax Receivable Agreement, then its obligations, or its successor's obligations, under the Tax Receivable Agreement to make payments thereunder would be based on certain assumptions, including an assumption that Blocker would have sufficient taxable income to fully utilize all potential future tax benefits that are subject to the Tax Receivable Agreement.

As a result of the foregoing, (i) Blocker could be required to make payments under the Tax Receivable Agreement that are greater than the specified percentage of the actual benefits it ultimately realizes in respect of the tax benefits that are subject to the Tax Receivable Agreement, and (ii) if it elects to terminate the Tax Receivable Agreement early, it would be required to make an immediate cash payment equal to the present value of the anticipated future tax benefits that are the subject of the Tax Receivable Agreement, which payment may be made significantly in advance of the actual realization, if any, of such future tax benefits. In these situations, Blocker's obligations under the Tax Receivable Agreement could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control of the Company. There can be no assurance that Blocker will be able to fund or finance its obligations under the Tax Receivable Agreement.

Blocker will not be reimbursed for any payments made to the Tax Receivable Recipients in the event that any tax benefits are disallowed

Payments under the Tax Receivable Agreement will be based on the tax reporting positions that Blocker determines, and the IRS or another tax authority may challenge all or part of the tax basis increases, as well as other related tax positions Blocker takes, and a court could sustain such challenge. If the outcome of any such challenge would reasonably be expected to materially affect a recipient's payments under the Tax Receivable Agreement, then Blocker will not be permitted to settle or fail to contest such challenge without the consent (not to be unreasonably withheld or delayed) of each Tax Receivable Recipient that directly or indirectly owns at least 15% of the outstanding Class B Non-Voting Units. Blocker will not be reimbursed for any cash payments previously made under the Tax Receivable Agreement in the event that any tax benefits initially claimed by Blocker and for which payment has been made are subsequently challenged by a taxing authority and are ultimately disallowed. Instead, any excess cash payments made by Blocker to a Tax Receivable Recipient will be netted against any future cash payments that Blocker might otherwise be required to make under the terms of the Tax Receivable Agreement. However, Blocker might not determine that Blocker has effectively made an excess cash payment to a Tax Receivable Recipient for a number of years following the initial time of such payment and, if any of Blocker's tax reporting positions are challenged by a taxing authority, Blocker will not be permitted to reduce any future cash payments under the Tax Receivable Agreement until any such challenge is finally settled or determined. As a result, payments could be made under the Tax Receivable Agreement in excess of the tax savings that Blocker realizes in respect of the tax attributes with respect to a Tax Receivable Recipient that are the subject of the Tax Receivable Agreement.

Fluctuations in the Company's tax obligations and effective tax rate and realization of the Company's deferred tax assets may result in volatility of the Company's operating results

The Company will be subject to taxes by the Canadian federal, state, local and foreign tax authorities, and the Company's tax liabilities will be affected by the allocation of expenses to differing jurisdictions. The Company records tax expense based on estimates of future earnings, which may include reserves for uncertain tax positions in multiple tax jurisdictions, and valuation allowances related to certain net deferred tax assets. At any one time, many tax years may be subject to audit by various taxing jurisdictions. The results of these audits and negotiations with taxing authorities may affect the ultimate settlement of these matters. The Company expects that throughout the year there could be ongoing variability in the quarterly tax rates as events occur and exposures are evaluated. The Company's future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- tax effects of share-based compensation;
- changes in tax laws, regulations or interpretations thereof; or
- future earnings being lower than anticipated in countries where the Company has lower statutory tax rates and higher than anticipated earnings in countries where the Company has higher statutory tax rates.

In addition, the Company's effective tax rate in a given financial statement period may be materially impacted by a variety of factors including but not limited to changes in the mix and level of earnings, varying tax rates in the different jurisdictions in which the Company operates, fluctuations in valuation allowances, deductibility of certain items, or by changes to existing accounting rules or regulations. Further, tax legislation may be enacted in the future which could negatively impact the Company's current or future tax structure and effective tax rates. The Company may be subject to audits of income, sales, and other transaction taxes by federal, state, local, and foreign taxing authorities. Outcomes from these audits could have an adverse effect on the Company's operating results and financial condition.

General

Although the Company believes that the above risks fairly and comprehensibly illustrate all material risks facing the Company, the risks noted above do not necessarily comprise all those potentially faced by the Company as it is impossible to foresee all possible risks.

Forward-Looking Statements May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking statements. By its nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable

ITEM 2. PROPERTIES

As of December 31, 2022, Alpine's assets consisted of a total leasehold position of 432,476.81 gross and 312,909.76 net acres, including the Hawkville area, the Giddings area, and the Holbrook Basin area. For the three months ended December 31, 2022, Alpine had 30.9 net wells (37 gross wells) with a net production rate of 14,445 BOE per day (gross production rate of 22,588 BOE per day). During 2022, Alpine maintained average net production per day of 10,513 BOE during 2022 (gross production rate of 16,145 BOE per day). During 2022, Alpine operated one rig exclusively in the Hawkville area, and one rig exclusively in the Giddings area, and one rig that traveled between the two areas. Approximately 49%, 40%, and 11% of production from Alpine's assets was attributable to oil, natural gas, and NGLs, respectively, for the year ended December 31, 2022.

The Hawkville Assets are located in Webb and La Salle Counties, Texas, in the core of the Eagle Ford Shale, and include 14,363.96 gross and 14,312.64 net acres. The acreage comprising the Hawkville Assets also includes the Austin Chalk formation overlying the Eagle Ford Shale. The Austin Chalk formation has shown itself to be an independent reservoir from the Eagle Ford Shale and represents a very attractive development target.

The Giddings Assets in the Austin Chalk area are located in Austin, Fayette, Lee, Robertson and Washington Counties, Texas, and include 9,004.14 gross and 7,582.80 net acres. There are several notable producing areas along the Austin Chalk trend, the largest of which is the Giddings area. Recent improvements in drilling and completion technologies have unlocked new development opportunities in the Giddings area. Wells drilled in recent years have helped to substantiate the strong economic viability of new drilling activity across the Austin Chalk formation.

The Giddings Assets in the Eagle Ford area are located in Fayette, Lee and Washington Counties, Texas, and include 134,198.18 gross and 16,103.79 net acres. While development has focused on the Austin Chalk, the Eagle Ford may still be shown to have potential in the future.

The Holbrook Basin Assets are located in Apache, Navajo and Coconino Counties, Arizona, and include 274,910.53 gross and net acres. Development of these assets for Helium is pending further research and planning.

Preparation and Internal Controls Over Reserves Estimates

All the proved oil and natural gas reserves disclosed in this Annual Report on Form 10-K are based on reserve estimates determined and prepared by independent reserve engineers W.D. Von Gonten Engineering, LLC. ("**WDVG**"), a leader of petroleum property analysis for industry and financial institutions. WDVG performs consulting petroleum engineering services under Texan Board of Professional Engineers Registration No. F-1855. Within WDVG, the technical person primarily responsible for preparing the estimates set forth in the WDVG letter dated February 3, 2023, filed as an exhibit to this Annual Report on Form 10-K, was Mr. William D. Von Gonten, Jr. Mr. Von Gonten has been a practicing consulting petroleum engineer at WDVG since 1995. Mr. Von Gonten is a Registered Professional Engineer in the State of Texas (License No. 73244) and has over 35 years of practical experience in petroleum engineering, with over 35 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1988 with a Bachelor of Science degree in Petroleum Engineering. Mr. Von Gonten meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

The proved oil and natural gas reserves disclosed in this Annual Report on Form 10-K are based on reserve estimates determined and prepared by independent reserve engineers primarily using decline curve analysis to determine the reserves of individual producing wells. To establish reasonable certainty with respect to our estimated proved reserves, the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using volumetric estimates or performance from analogous wells in the surrounding area. These wells were considered to be analogous based on production performance from the same formation and completions using similar techniques. The technologies and economic data used to estimate our proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy before consultation with independent reserve engineers. This consultation included review of properties, assumptions and available data. Internal reserve estimates were compared to those prepared by independent reserve engineers to test the estimates and conclusions before the reserves were included in this Annual Report on Form 10-K. The accuracy of the reserve estimates is dependent on many factors, including the following:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future costs, which could vary considerably from actual costs;
- the accuracy of economic assumptions; and
- the judgment of the personnel preparing the estimates.

The Company's Chief Operating Officer, Mr. Mike McCoy, is the technical professional primarily responsible for overseeing the preparation of our reserves estimates. He has a Bachelor of Science degree in Petroleum Engineering from Texas A&M University with over 30 years of practical industry experience, including over 30 years of estimating and evaluating reserve information. His qualifications meet or exceed the Society of Petroleum Engineers' standard requirements to be a professionally qualified Reserve Estimator and Auditor.

We encourage ongoing professional education for our engineers and analysts on new technologies and industry advancements as well as refresher training on basic skill sets. In order to ensure the reliability of reserves estimates, the Company personnel responsible for reserves ("**Reserves Personnel**") follows comprehensive SEC-compliant internal controls and policies to determine, estimate and report proved reserves including:

- confirming that we include reserves estimates for all properties owned and that they are based upon proper working and net revenue interests;
- ensuring the information provided by other departments within the Company such as Accounting is accurate;
- communicating, collaborating, and analyzing with technical personnel in our business units;
- comparing and reconciling the internally generated reserves estimates to those prepared by third parties; and
- utilizing experienced reservoir engineers or those under their direct supervision to prepare reserve estimates.

Reserves Personnel works closely with independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are presented to the Reserves Committee. In addition to reviewing the independently developed reserve reports, the Reserves Committee also periodically meets with the independent petroleum consultants that prepare estimates of proved reserves.

Drilling Activity

The following table sets forth the number of gross and net productive and non-productive wells drilled in the years ended December 31, 2022, 2021, and 2020 by region. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.

	For the year ended December 31,					
Giddings	**2022**		**2021**		**2020**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory						
Productive	–	–	–	–	–	–
Dry	–	–	–	–	–	–
Development						
Productive	11	7.27	10	5.78	7	5.82
Dry	–	–	–	–	–	–
Total						
Productive	11	7.27	10	5.78	7	5.82
Dry	–	–	–	–	–	–

	For the year ended December 31,					
Hawkville	**2022**		**2021**		**2022**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory						
Productive	–	–	–	–	–	–
Dry	–	–	–	–	–	–
Development						
Productive	7	5.65	–	–	–	–
Dry	–	–	–	–	–	–
Total						
Productive	7	5.65	–	–		
Dry	–	–	–	–		

Acreage and Well Count

The following table summarizes gross and net developed and undeveloped acreage as of December 31, 2022 by region (net acreage is our percentage ownership of gross acreage).

Acres	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Giddings	9,004	7,583	-	-	9,004	7,583
EagleFord	-	-	134,918	16,104	134,198	16,104
Hawkville	749	749	13,615	13,564	14,364	14,313
Holbrook	-	-	274,910	274,910	274,910	274,910
Total	9,753	8,332	422,723	304,578	432,476	312,910

Delivery Commitments

Alpine Summit has firm transportation commitments for 90 Mcf/day of dry gas for certain of its Hawkville Assets extending through November 2023, increasing to 150 Mcf/day beginning in November 2023 and extending for five years. We view this firm transportation as an asset to the Company given the significant flowback restrictions surrounding our competitors' ability to access the market. Independent reservoir analysis has confirmed that the Company's completed and developable locations are more than sufficient to meet these transportation commitments.

In the event the Company is unable to meet these delivery commitments due to an inability to continue developing locations, we would still be obligated to pay the transportation fees associated with this firm commitment, but we do have the ability to remarket this firm transportation to mitigate this potential risk.

For a further discussion of our oil and natural gas reserves, refer to Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and *Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).*

ITEM 3. LEGAL PROCEEDINGS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was the subject of, during its most recently completed financial year, that were or are material to it, and there are no such material legal proceedings that the Company is currently aware of that are contemplated.

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

Market Information

The Company's Subordinate Voting Shares are listed on the TSX-V under the symbol "ALPS.U" and on the Nasdaq under the symbol "ALPS".

Shareholders

As of March 21, 2023, there were 139 holders of record of our Subordinate Voting Shares.

Dividends

The Company declared monthly dividends totaling approximately $12.4 million for the year ended December 31, 2022. The cash dividends were declared for all issued and outstanding Subordinate Voting Shares, Multiple Voting Shares, and Proportionate Voting Shares. Dividends are approved at the sole discretion of the Company's Board, and the Company's Corporate Credit Facility can limit the dividends the Company is able to pay unless the Company meets certain covenants in accordance with its credit agreement.

On February 23, 2023, the Board deemed it prudent to suspend its monthly dividend payments, beginning in March 2023, until further notice. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board. Our Board's determination of any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the Board deems relevant at the time of such determination.

Equity Compensation Plans

The following table sets forth the number of Subordinate Voting Shares to be issued upon exercise of outstanding convertible securities, the weighted-average exercise price of such outstanding convertible securities and the number of Subordinate Voting Shares remaining available for future issuance under our equity compensation plans as at December 31, 2022, which have been approved by the Company’s shareholders. The Company does not have any equity compensation plans that have not been approved by shareholders.

Plan Category	Number of Subordinate Voting Shares to be issued upon exercise of outstanding securities	Weighted-average exercise price of outstanding securities	Number of Subordinate Voting Shares remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by Shareholders			
Stock Options	2,834,288	$3.56	524,233
Restricted Stock Units	82,500	n/a	747,841
Deferred Share Units	226,335	n/a	277,443
Total	3,143,123		1,549,517

Recent Sales of Unregistered Securities

The following information represents securities sold by the Company for the period covered by this Annual Report which were not registered under the Securities Act. Included are new issues, securities issued upon conversion from other share classes, and securities issued in exchange for property, services, or other securities.

On January 19, 2022, Origination issued 826,063 Class B non-voting units of Origination ("**HB2 Units**") in connection with the exercise by ten partners of their put right provided to them by the second development partnership of the Company (which are exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company). The HB2 Units were issued on a private placement basis in accordance with an exemption from the registration requirements of the Securities Act under Rule 506(b), as a transaction not involving any public offering. The sale was made only to "accredited investors" was not made by any general solicitation or advertising.

On May 19, 2022, Origination issued 894,929 HB2 Units in connection with the exercise by twelve partners of their put right provided to them by the third development partnership of the Company (which are exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company). The HB2 Units were issued on a private placement basis in accordance with an exemption from the registration requirements of the Securities Act under Rule 506(b), as a transaction not involving any public offering. The sale was made only to "accredited investors" was not made by any general solicitation or advertising.

On June 1, 2022, the Company granted 1,214,321 restricted stock units ("**RSUs**") to certain officers, directors and employees of the Company pursuant to the terms of its equity incentive plan (the "**Equity Incentive Plan**") and 88,694 deferred share units ("**DSUs**") to certain non-executive directors of the Company pursuant to the terms of its deferred share unit plan (the "**DSU Plan**"). Each RSU entitles the holder to acquire one subordinate voting share in certain circumstances, subject to vesting requirements, provided that such RSU may also be settled in cash, all in accordance with the Equity Incentive Plan, and each DSU entitles the holder to acquire one subordinate voting share in certain circumstances, subject to vesting requirements, provided that such DSU may also be settled in cash, all in accordance with the DSU Plan. The grants were made on a private placement basis in accordance with an exemption from the registration requirements of the Securities Act under Rule 506(b), as a transaction not involving any public offering. The sale was made only to "accredited investors" was not made by any general solicitation or advertising.

On July 26, 2022, 706,975 HB2 Units were issued in connection with the exercise by nine partners of their put right provided to them by the Fourth Development Partnership of the Company (which are exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company). The Class B non-voting units were issued on a private placement basis in accordance with an exemption from the registration requirements of the Securities Act under Rule 506(b), as a transaction not involving any public offering. The sale was made only to "accredited investors" was not made by any general solicitation or advertising.

On November 30, 2022, 617,103 HB2 Units were issued in connection with the exercise by twelve partners of their put right provided to them by the Red Dawn 1 development partnership (which are exchangeable on a one-for-one basis for Subordinate Voting Shares of the Company). The Class B non-voting units were issued on a private placement basis in accordance with an exemption from the registration requirements of the Securities Act under Rule 506(b), as a transaction not involving any public offering. The sale was made only to "accredited investors" was not made by any general solicitation or advertising.

On February 3, 2023, 499,794 HB2 Units were issued in connection with the exercise by six partners of their put right provided to them by the Fifth Development Partnership. The Class B non-voting units were issued on a private placement basis in accordance with an exemption from the registration requirements of the Securities Act under Rule 506(b), as a transaction not involving any public offering. The sale was made only to "accredited investors" was not made by any general solicitation or advertising.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers:

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares (or units) purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1, 2022 - October 31, 2022	276,900	$5.41	276,900	1,105,983 [2]
November 1, 2022 - November 30, 2022	226,000[3]	$5.35	223,900	882,083 [2]
December 1, 2022 - December 31, 2022	33,600[4]	$5.21	32,900	849,183 [2]
Total	536,400	$5.32	533,700	n/a

[2] Represents the maximum number of shares that may yet be purchased under the Company's NCIB, which commenced on June 10, 2022 and will conclude on the earlier of the date on which purchases under the NCIB have been completed and June 9, 2023. As of the time of commencement, the Company may purchase for cancellation up to 1,648,783 Subordinate Voting Shares under the NCIB.

[3] 2,100 of the 226,000 Subordinate Voting Shares purchased in November 2022 were purchased by Craig Perry, our Chief Executive Officer, on the open market at an average price of $5.41 per share. The remaining 223,900 Subordinate Voting Shares were purchased by the Company under our NCIB.

[4] 700 of the 33,600 shares purchased in December 2022 were purchased by Craig Perry, our Chief Executive Officer, on the open market at a price of $5.35 per share. The remaining 32,900 Subordinate Voting Shares were purchased by the Company under our NCIB.

ITEM 6. [RESERVED]

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

The following discussion and analysis should be read in conjunction with other sections of this Annual Report, including but not limited to "Forward-Looking Statements", Part 1. Item 1A Risk Factors, and our consolidated financial statements and the accompanying notes included in Part II. Item 8. Financial Statements and Supplementary Data of this Annual Report.

The Company historically prepared its consolidated financial statements under International Financial Reporting Standards. For the year ended and as at December 31, 2022 the consolidated financial statements of the Company and its subsidiaries have been prepared in conformity with accounting principles generally accepted in the United States of America ("US GAAP"). US GAAP has been applied retrospectively.

This section of our Annual Report discusses 2022 and 2021 items and year-over-year comparisons between those periods. Amounts are stated in US dollars unless otherwise noted.

OVERVIEW AND HIGHLIGHTS

The Company is a U.S. oil and natural gas development company focused on maximizing return on equity. The Company has focused its drilling activity in two main areas, the Austin Chalk and Eagle Ford formations in the Giddings Field in Austin, Fayette, Lee, Robertson and Washington Counties, TX (the "Giddings Assets") and the Hawkville Field in Webb and LaSalle Counties, TX (the "Hawkville Assets").

For future periods, the Company plans to continue to develop its existing and adjacent footprint over the next several years while also evaluating additional development projects that fit its investment criteria.

As of December 31, 2022, the Company's assets consisted of a total leasehold position of 432,477 gross and 312,910 net acres, including the Hawkville area, the Giddings area, and the Holbrook Basin area, as follows:

- Giddings Assets: (a) in the Austin Chalk area include 9,004 gross and 7,583 net acres, and (b) in the Eagle Ford area include 134,198 gross and 16,104 net acres.

- Hawkville Assets: include 14,364 gross and 14,313 net acres.

- The Holbrook basin assets are located in Apache, Navajo and Coconino Counties, Arizona, and include 274,911 gross and net acres. Development of these assets for Helium is pending further research and planning.

2022 Highlights

- Oil and natural gas sales (net of royalties) of $195.6 million for the year ended December 31, 2022 (December 31, 2021 - $70.8 million).

- Reported net income and comprehensive income of $44.4 million for the year ended December 31, 2022 (December 31, 2021 - loss of $32.6 million). Adjusted EBITDA[1] (defined below) of $140.1 million for the same period (December 31, 2021 - $46.2 million).

- Reported net income and comprehensive income attributable to the Company's common shareholders of $7.4 million for the year ended December 31, 2022 (December 31, 2021 - loss of $32.3 million)

- 18 new wells were brought onto production during 2022.

- For the three months ended December 31, 2022, Alpine had 30.9 net wells (37 gross wells) with a net production rate of 14,445 BOE per day (gross production rate of 22,588 BOE per day).

- Average net production per day of 10,513 BOE during 2022 (gross production rate of 16,145 BOE per day) an increase of 156% year over year due to extensive drilling activity.

- Development projects continued to be funded via the development partnership structures, to facilitate continued drilling initiatives.

[5] This is a non-GAAP financial measure. Refer to the “Non-GAAP Financial Measures” section for further information and the detailed reconciliation to the most directly comparable measure under GAAP.

- Entered into the ABS Facility for total borrowings of $135 million. As of December 31, 2022, approximately $110 million was outstanding on the ABS Facility.

- Expanded the size of the Corporate Credit Facility to a maximum size of $65 million. As of December 31, 2022 $41.5 million was drawn under the Corporate Credit Facility.

- Listing on the Nasdaq Stock Market of the Company's Class A Subordinate Voting Shares on September 28, 2022, trading under the ticker symbol "ALPS".

- Implemented a dividend distribution policy, starting January 2022, where monthly dividends of $0.03 per share for each of the subordinated voting shares and proportionate voting shares and $3.00 per each share of the multiple voting shares were declared each month, with aggregate dividends declared and paid in 2022 of $12,416,759 (2021 - $nil).

Subsequent Event Highlights

- The Company continued with its monthly dividend program, $0.03 per SVS ($3.00 per MVS and $0.03 per PVS) for January and February 2023.

- On January 20, 2023, the Company successfully completed the payout and liquidation of its development partnership five and concurrently formed development partnership seven.

- On February 23, 2023, the Company announced the suspension of the monthly dividend payments commencing in March 2023.

- The Company announced the commencement of a strategic review of assets on February 23, 2023.

- On March 3, 2023, the Company announced the resignation of Darren Tangen from the Board of Directors and subsequent hiring of James Russo as his replacement.

- On March 8, 2023, the Company announced the hiring of Stephens Inc. as its financial advisor to pursue an asset sale.

- In March 2023, the Company received covenant waivers on the Corporate Credit Facility and the ABS Facility until July 1, 2023 for potential future covenant breaches.

Oil and Natural Gas Reserves

The Company's year-end reserve evaluation as of January 1, 2023, was prepared by W.D. VonGonten & Co. in a report dated February 3, 2023 (the "Reserves Report"). The Reserve Report evaluates all of the Company's oil, natural gas, and NGL reserves, and uses pricing estimates in accordance with guidelines established by the United States Securities and Exchange Commission. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions.

Highlights of the Reserves Report include:

- Proved developed producing reserves ("PDP") were 15.8 million BOE and total proved reserves ("1P") were 24.0 million BOE.

- The PDP reserves have a composition of 24% oil and 76% natural gas and NGL, whereas the 1P reserves were composed of 18% oil and 82% natural gas and NGL.

- Net future development costs were $4.0 million for PDP and $75.5 million for 1P.

For details on the reserves data and estimates, as well as changes, refer to *Item 8. Financial Statements and Supplementary Data - Supplemental Oil and Gas Information (Unaudited).*

OPERATIONAL AND FINANCIAL RESULTS

Net Oil and Gas Revenues

For the year ended December 31,		2022		2021
Oil	**$**	**97,438,790**	$	50,868,794
Natural gas		**77,966,801**		10,286,929
NGLs		**20,243,366**		9,641,067
Total	**$**	**195,648,957**	$	70,796,790
% of total oil and gas revenue by product type:				
Oil weighting		**49.8%**		71.9%
Natural gas weighting		**39.9%**		14.5%
NGL weighting		**10.3%**		13.6%

Our revenues vary from year to year primarily as a result of changes in commodity prices and production volumes. In 2022, oil and gas revenues increased by $124,852,168, an increase of 176.4% from 2021, driven by an 155.7% increase in production volumes and an increase in the average per BOE realized selling price of 8.1%, excluding the effect of commodity derivatives.

<u>*Production volumes:*</u>

The higher production in 2022 is a result of the addition of 18 new wells, with a primary focus on Hawkville gas wells attributing to the change in sales mix.

The production for the years ended December 31, 2022 and 2021, reflecting the Company's working interests and net of royalties, are as follows:

Year ended December 31,	2022	2021	% Change
Production:			
Oil (bbl)	**1,030,226**	743,427	38.6%
Natural gas (Mcf)	**13,316,867**	2,398,310	455.3%
NGLs (bbl)	**587,623**	357,769	64.2%
Total BOE[1]	**3,837,327**	1,500,914	155.7%
Average Daily Production:			
Oil (bbl/d)	**2,823**	2,037	
Natural gas (Mcf/d)	**36,485**	6,571	
NGLs (bbl/d)	**1,610**	980	
Total BOE[1] per day	**10,513**	4,111	
Production Weighting on a BOE basis:			
Oil	**26.8%**	49.5%	
Natural gas	**57.9%**	26.7%	
NGL	**15.3%**	23.8%	

1 *Natural gas is converted to a barrel of oil equivalent ("BOE") at the rate of one barrel equaling six Mcf (defined as one thousand cubic feet) based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.*

Average sales price:

On a per-BOE basis, the Company's average realized price for the year ended December 31, 2022 increased compared to the same period of 2021 by $3.82 per BOE, reflecting a 8.1% increase. The increase in sales prices is primarily due to the increase in the commodity price indices for oil, natural gas, and NGL. However, the realized average sales price per BOE also reflects the increased production of natural gas and NGLs at a lower overall per BOE price.

The average realized sales prices for the years ended December 31, 2022 and 2021, are as follows:

For the year ended December 31,	**2022**	2021	**% Change**
Oil - Bbl	**$ 94.58**	$ 68.42	38.2%
Natural gas - Mcf	**$ 5.85**	$ 4.29	36.5%
NGL - Bbl	**$ 34.45**	$ 26.95	27.8%
Average sales price per BOE	**$ 50.99**	$ 47.17	8.1%

Commodity Derivative Instruments

The future results of the Company's oil and natural gas operations will be affected by market prices of oil and natural gas which is affected by numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil, natural gas and natural gas liquid products, economic disruptions, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company enters into various commodity price derivative instruments to manage the price risk attributable to part of its future production. As the Company's derivatives are not designated for hedge accounting, the changes in fair value of the derivatives are recognized in income (loss) each period, creating earnings volatility in connection with outstanding derivatives. As commodity prices increase or decrease, such changes will have the opposite effect on the fair value of the derivatives.

At December 31, 2022, the net fair value of the open commodity derivatives was an asset position of $3,077,079 (2021 - liability position of $20,424,601). The change from 2021 is primarily due to the volume of outstanding derivatives as well as changes in the forward commodity prices relatively to the fixed price of the derivatives.

The Company's net loss on commodity derivatives for the year ended December 31, 2022 was $10,023,495 (2021 - $33,525,453). This amount consists of an unrealized gain of $26,246,351 (2021 - loss of $15,903,217) and realized losses of $36,269,846 million (2021 - loss of $17,622,236).

Refer to Note 18 of the financial statements for additional details.

Management of cash flow variability is an integral component of the Company's business strategy. Business conditions are monitored regularly and reviewed by the Company to establish risk management guidelines in carrying out the Company's strategic risk management program.

Expenses

The following table summarizes the Company's expenses and other income (expenses) for the periods indicated:sss

For the year ended December 31,	**2022**	2021
Expenses:		
Production costs and transportation	**$ 41,495,709**	$ 12,087,223
General and administrative	**26,090,160**	25,021,117
Depletion and depreciation	**62,082,471**	23,497,715
Asset retirement obligation accretion	**43,756**	24,209
Total expenses	**129,712,096**	60,630,264
Operating Income	**55,913,366**	(23,358,927)
Other income (expenses)		
Finance and interest expense	**(13,428,333)**	(5,727,544)
Acquisition costs	**-**	(1,567,967)
Income (loss) before income taxes	**42,485,033**	(30,654,438)

Deferred income tax provision (benefit)		**(1,928,319)**		**1,928,319**
Net income (loss) and comprehensive income (loss)		**44,413,352**		**(32,582,757)**
Net income attributable to redeemable non-controlling interest		**33,796,021**		13,091,908
Net income (loss) attributable to non-controlling interest		**3,189,196**		(13,330,237)
Net income (loss) attributable to the Company	**$**	**7,428,135**	$	(32,344,428)
Select Expenses per BOE:				
Production costs and transportation	**$**	**10.81**	$	8.05
General and administrative	**$**	**6.80**	$	16.67
Depletion and depreciation	**$**	**16.18**	$	5.66
Finance and interest expense	**$**	**3.50**	$	3.82

Production and Transportation Costs

Total production and transportation costs for the year ended December 31, 2022, increased by $29,408,486, an increase of 243% when compared to the same period of 2021, primarily due to the overall increased production noted above. On a per BOE basis, the production and transportation costs increased by $2.76, an increase of 34%, due to higher operating costs for wells brought online in 2022, primarily relating to higher water disposal, fuel, and trucking costs, as well as overall market increases for service costs. The higher service costs are mainly due to inflation and market availability.

General and Administrative Costs

General and administrative costs for the year ended December 31, 2022, remained relatively consistent with an increase of $1,069,043 or 4%, when compared to the same period of 2021. This increase was primarily due to an increase in employee salaries and benefits of $3,709,863, an increase in professional, legal and advisory costs of $1,042,547, and office and administrative costs of $735,312, as well as increases in other items such as software, and lease expenses, and partially offset by the reduction to stock-based compensation of $4,281,056. From a per BOE perspective, the general and administrative costs reduced by $9.87 per BOE, a reduction of 59%, as a result of increased production levels noted above.

Depreciation, Depletion, and Amortization

The depreciation, depletion, and amortization expense consist of depletion on the Company's evaluated oil and gas properties. Depletion expense increased for the year ended December 31, 2022, by $38,584,756, an increase of 164% as compared to the same period of 2021 due to an increase in production, as well as an increase in the evaluated properties that are part of the depletion base. Depletion expense on a BOE basis also increased by $0.52 per BOE, an increase of 3%, reflecting the higher costs incurred on the new wells, due to inflation and market availability.

Finance and Interest Expense

Finance and interest expense for the year ended December 31, 2022, increased by $7,700,789, an increase of 134%, as compared to the same period of 2021 due to the increase in overall borrowings. The main increase relates to the financing and interest costs on the ABS Facility, as well as the Corporate Credit Facility, as defined in the financial statements. On a per BOE basis, the finance and interest expense has decreased by $0.32 per BOE, a decrease of 8%, due to the increased production in 2022.

Income Tax Expense (Benefit)

For the year ended December 31,2022, the Company recognized an income tax benefit of $1,928,319, resulting in an effective tax benefit of 4.5%, compared to an income tax expense of $1,928,319 for the year ended December 31, 2021, resulting in an effective tax rate of 5.9%. The overall change in the Company’s effective tax rate for the year ended December 31, 2022, from the previous year is primarily due to: (i) changes in amounts of income (loss) not subject to corporate tax and, (ii) current year activity causing the reversal of a previously recorded deferred tax expense resulting from temporary differences in recognition of items related to cost recovery of oil and natural gas properties.

Additionally, the Company assesses the likelihood that its deferred tax assets will be recovered from future taxable income and, to the extent it believes that recovery is more likely than not, it does not establish a valuation allowance reserve against the recorded net deferred tax assets. As of December 31, 2022, the Company recorded a valuation allowance on its net deferred tax assets after reflecting the reversal of previously recorded deferred tax liabilities due to current year activity. *Refer to Note 15 of the financial statements for additional details.*

Non-GAAP Financial Measures:

Within this report, references are made to terms which are not recognized under GAAP. Specifically, "field operating netbacks", "adjusted EBITDA", and measurements "per commodity unit" and "per BOE" do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. The Company's management uses these non-GAAP supplemental measures to benchmark operations against prior periods and peer group companies and believes they provide useful supplemental information that can be used by investors, lenders, analysts and other parties to analyze the Company's performance and financial results.

Field Operating Netbacks

Field operating netbacks are used by management to assess operational performance of assets. Field operating netbacks are calculated by deducting depletion and commodity derivatives from the gross margin and is presented on a per BOE basis.

The Field Operating Netback for the years ended December 31, 2022 and 2021 are as follows:

For the year ended December 31,		**2022**		2021
Revenue from product sales	**$**	**195,648,957**	$	70,796,790
Gain/(loss) on derivative instruments		**(10,023,495)**		(33,525,453)
Less: Production costs and transportation		**(41,495,709)**		(12,087,223)
Less: Depreciation, depletion and amortization		**(62,082,471)**		(23,497,715)
Gross margin		**82,047,282**		1,686,399
Remove: Gain/(loss) on derivative instruments		**10,023,495**		33,525,453
Remove: Depreciation, depletion and amortization		**62,082,471**		23,497,715
Field operating netback - total	**$**	**154,153,248**	$	58,709,567
Field operating netback - per BOE	**$**	**40.17**	$	39.11

For the year ended December 31, 2022, the Field Operating Netback per BOE remained relatively consistent, with an increase of $1.06 per BOE when compared to 2021. This reflects an offset of the $2.76 per BOE increase in production costs and transportation, with the increase in the average realized sales price per BOE of $3.82.

Adjusted EBITDA

Adjusted earnings before interest, taxes, depletion and amortization (“Adjusted EBITDA”), is a non-GAAP measure that is used to supplement the Company’s reported financial performance or position. The Company believes that Adjusted EBITDA, considered along with net earnings (loss), is a relevant indicator of trends relating to our operating performance and provides management and investors with additional information for comparison of our operating results to the operating results of other companies. All figures presented do not reflect any potential impact of non-controlling interests or redeemable non-controlling interests. The Company’s calculation of Adjusted EBITDA is net income/(loss) adding back finance and interest expense, depletion and depreciation, impairment, gains/losses on commodity derivatives, and non-recurring costs.

The following table provides a reconciliation of net income/(loss) before redeemable non-controlling interest and non-controlling interest to Adjusted EBITDA:

Year ended December 31,		**2022**		2021
Net income/(loss):	**$**	**44,413,352**		($32,582,757)
(+) Depreciation, depletion, and amortization expense		62,082,471		23,497,715
(+) Finance and interest expense		13,428,333		5,727,544
(+) Stock based compensation expense		10,197,720		14,478,776
(+) Acquisition costs		-		1,567,967
(+) Derivative commodity contract (gains)/losses		10,023,495		33,525,453
Adjusted EBITDA	**$**	**140,145,371**	$	46,214,698

FINANCING, LIQUIDITY AND CAPITAL RESOURCES

Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs that maintain and increase production and reserves, to acquire strategic oil and gas assets, to repay current liabilities and debt and ultimately to provide a return to shareholders. The Company's capital programs are funded by existing working capital, various lending facilities and redeemable non-controlling interests (discussed below) and cash provided from operating activities. Fluctuations in commodity prices, product demand, interest rates and various other risks may impact capital resources and capital expenditures.

During 2022, the main financing related transactions included the following:

- **Asset backed securitization facility (the "ABS Facility"):**

  The Company entered into two tranches of borrowings under the ABS Facility, for a total size of $135 million.

  On April 27, 2022, Tranche 1 of the ABS Facility was drawn for $80 million and carries an interest rate of LIBOR+6% (with a 1% LIBOR floor) for the initial year, LIBOR +12% for the second year. Tranche 1 has an initial maturity date of one year, with the Company having the option to extend an additional year to an ultimate maturity date of April 2024.

  On September 12, 2022, Tranche 2 of the ABS Facility was drawn for an additional $55 million and carries an interest rate of LIBOR+8% (with a 1% LIBOR floor) for the initial year, LIBOR +14% for the second year. Tranche 2 has an initial maturity date of one year, with the Company having the option to extend an additional year to an ultimate maturity date of September 2024.

  All borrowings under the ABS Facility are secured by working interests in a subset of the Company's producing assets.

  As at December 31, 2022, the Company had $109,982,677 of principal outstanding under the ABS Facility.

- **Corporate Credit Facility:**

  During the first quarter of 2022, the Company replaced its previous credit facility, which had a $12,500,000 borrowing capacity. The new corporate credit facility had a borrowing capacity of $30,000,000, which was subsequently increased in October 2022 to $65,000,000, subject to quarterly borrowing base determinations by the lender. The facility charges interest at prime +2.25% and had a one-year maturity. A subset of certain Company working interests in producing assets have been secured in connection with the Corporate Credit Facility.

  As at December 31, 2022, the Company ad drawn $41,500,000 under the Corporate Credit Facility (2021 - $2,200,000). The borrowing base as at December 31, 2022 was $64,435,764 (2021- $6,579,750).

- **Goldman Facility**

  The Company had borrowings under a credit facility with Goldman Sachs (the "Goldman Facility"), which carried an interest rate of LIBOR+6% (with a 1% LIBOR floor) and a maturity date of December 22, 2031. All borrowings under the Goldman Facility were secured by the Company's oil and gas producing wells as well as all assets of three of the Company's subsidiaries.

  In April 2022, in connection with the ABS Facility (above), the Company repaid the Goldman Facility in full. The principal borrowing under this facility as at December 31, 2022 was $nil (2021 - $25,237,409).

- **Asset Backed Preferred Instruments:**

  The Company had previously issued mandatorily redeemable instruments as part of a share buy-back structure. These instruments were fully repaid and settled in 2022.

- **Development Partnerships:**

  The Company utilizes development partnerships as a mechanism to partially finance its development projects and activities. As part of the development partnerships, investors will provide funding to be used for the development of specific wells, in return, the investors will receive partnership units that provide a specified return, plus participation in the residual of those wells that can be realized via redemption.

Due to the redemption feature, the development partnership interests issued to external investors are accounted for as redeemable non-controlling interest.

For the year ended December 31, 2022, the redeemable non-controlling interests provided cash inflows of $53,728,933 (2021 - $41,042,693), and cash outflows for the distribution and settlement of $10,369,504 (2021 - $6,388,870). Of the total redeemable non-controlling interest that received distributions and/or was settled, the remaining non-cash balance related to settlements via the issuance of redeemable non-controlling interests for a new development partnership, via non-controlling interest shares, or via oil and gas property dispositions

As at December 31, 2022, the redemption value of the redeemable non-controlling interest was $107,583,737 (2021 - $46,552,839).

Refer to Note 2 and Note 9 of the financial statements for additional details.

<u>*Working Capital and Liquidity Risk*</u>

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities as they become due.

At December 31, 2022 the Company had a working capital deficit of $162,980,101, compared to a deficit of $36,148,466 as at December 31, 2021. Current assets increased by $12,104,044 compared to 2021, primarily due to an increase in accounts receivables due to higher oil and gas revenues, as well as increases in restricted cash and derivative assets, and partially offset by a reduction in cash and cash equivalents. This was offset by an increase in current liabilities of $138,935,679 primarily due to increases in accounts payable and accrued liabilities as well as current portions of borrowings, due to increased capital expenditures on oil and natural gas properties, and partially offset by a reduction to the current portion of the derivative liabilities.

Due to the working capital deficit, the Company does not currently have the cash resources to meet its current liabilities for the next twelve months. These factors raise substantial doubt about the Company's ability to continue as a going concern.

The Company's ability to continue as a going concern is dependent on its ability to generate sufficient cash flows from operations, as well as its ability to obtain financing via an asset sale and/or the issuances of debt and/or equity in the short term. While the Company believes it has sufficient forecasted funds to meet foreseeable obligations, there can be no assurance that the Company will be successful in its efforts to raise additional funds in the short term and its ability to generate sufficient operating cash flows.

Due to these factors, the Company may be unable to continue as a going concern. The financial statements do not include any adjustments related to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might be necessary should the Company be unable to continue as a going concern, and such adjustments could be material.

In an effort to increase liquidity, the Company has during and subsequent to the year ended December 31, 2022: (i) continued its drilling program to bring wells online and to increase cash flows from operating activities, (ii) raised funds through development partnerships, (iii) entered into a strategic review of assets and engaged Stephens Inc. for a potential asset sale, (iv) commenced the suspension of monthly dividends starting March 2023, (v) obtained waivers for covenant breaches on the Corporate Credit Facility and ABS Facility until July 1, 2023 in the event of a covenant breach, and (vi) obtained an extension to the initial maturity date of the first tranche of the ABS Facility until July 1, 2023.

Sources and Uses of Cash

The Company's sources and uses of cash are summarized as follows:

For the year ended December 31,		**2022**		2021
Net cash from operating activities	**$**	**92,902,136**	$	32,996,780
Net cash used for investing activities		**(212,210,813)**		(56,678,478)
Net cash from financing activities		**121,184,325**		29,414,953
Net change in cash and cash equivalents and restricted cash	**$**	**1,875,648**	$	5,733,255

Cash Flows from Operating Activities

The net cash from operating activities in 2022 increased by $59,905,356, an increase of 182% from 2021. The increase was driven by the increase in production, as well as changes to working capital and timing of cash receipts and disbursements.

Cash Flows used for Investing Activities

During the year ended December 31, 2022, the Company's cash flows used for investing activities increased by $155,532,335, an increased of 274% when compared to 2021, due to increased drilling and development of its oil and gas properties. For the evaluated oil and gas properties, the majority of the activity related to the drilling of horizontal wells in the Giddings and Hawkville Fields. The expenditures on unevaluated properties focused on the acquisition, exploration and development of those unevaluated assets.

Our cash flows used in investing activities reflects actual cash spending, which can lag several months from when the related costs were incurred. As a result, our actual cash spending is not always reflective of current levels of development activity.

Cash Flows from Financing Activities

During the year ended December 31, 2022, cash provided by and used in financing activities increased by $91,769,372, an increase of 312% when compared to 2021, primarily due to the increased net borrowings under the external debt facilities, as well as increases in the net proceeds from the issuance of redeemable non-controlling interests.

The net cash proceeds from the debt issuances were in part offset by the use of cash for the payments of dividends of $18,969,442, to both the Company's common shareholders, and dividends paid to its non-controlling interest holders, as well as the use of $4,324,915 in cash to repurchase and cancel the Company's shares.

Refer to the statements of cash flows of the financial statements for further details.

Off-Balance-Sheet Arrangements

The Company does not have any special-purpose entities nor is it a party to any arrangements that would be excluded from the consolidated balance sheet.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND POLICIES

The Company's financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP), which require management to make estimates, judgments and assumptions that affect the amounts reported in our financial statements and accompanying notes. Certain accounting policies are identified as critical because they require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain, and because the estimates are of material magnitude to revenue, expenses, cash flows from operations, income or loss and/or other important financial results. These accounting policies could result in materially different results should the underlying conditions change or the assumptions prove incorrect.

We consider the following to be our most critical accounting policies and estimates involving significant judgment or estimates. See Note 2 to the financial statements in this Annual Report for further details on our accounting policies as at December 31, 2022.

Going Concern

The financial statements have been prepared assuming that the Company will continue as a going concern, which contemplates continuity of operations, realization of assets, and liquidation of liabilities in the normal course of business.

Oil and Natural Gas Properties

The Company uses the full-cost method of accounting for its oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, and general and administrative expenses directly related to acquisition, exploration and development activities, but does not include any costs related to production, selling or general corporate administrative activities.

In determining the depletion capitalized costs of oil and natural gas properties are amortized using the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus estimates of future development costs by estimates of proved reserves quantities. Unproved and unevaluated property costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are considered proved or impaired. The Company reviews its unproved and unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization.

As a result, the determination of depletion can be significantly impacted by the costs identified as being part of the depletion base, and the proved reserves volumes and future development costs.

Similarly, the assessment of impairment of evaluated oil and gas properties is subject to the ceiling test. This ceiling test determines a limit, or ceiling, on the net capitalized costs of oil and natural gas properties. The net capitalized costs are limited to the lower of unamortized costs less related deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of: (a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) any income tax effects related to the properties involved.

Therefore, changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

Oil and Natural Gas Reserves Quantities and Standardized Measure of Future Net Revenue

Engineers and technical staff prepare the estimates of oil and natural gas reserves and associated future net revenues. While the Company has proved, probable and possible reserves, the Company has elected to present only proved reserves in this report. Proved reserves are defined as the quantities of oil 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 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 assessment of reported recoverable quantities of proved reserves includes estimates regarding production volumes, commodity prices, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Accordingly, reserves estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Any significant variance could materially and adversely affect the future reserves estimates, financial condition, results of operations and cash flows. The Company cannot predict the amounts or timing of future reserves revisions. If such revisions are significant, they could significantly affect future depletion of capitalized costs and result in an impairment of assets that may be material.

Estimates of proved oil and natural gas reserves are key inputs used for the calculations of depletion and the ceiling test. The estimated present value of future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. Oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. The associated commodity prices and the applicable discount rate used in estimates for depletion and the ceiling test are in accordance with guidelines established by the United States Securities and Exchange Commission. Under these guidelines, future net revenues are calculated using prices that represent the arithmetic averages of the first day-of-the-month oil and natural gas prices for the previous 12-month period, and a 10% discount factor is used to determine the present value of future net revenues.

The reserve assessment was completed by an external third-party engineering firm for the years ended December 31, 2022 and 2021 and reserves are internally updated for interim periods.

2023 OBJECTIVES AND OUTLOOK

During 2023, the Company plans on continuing to manage production of its primary assets in the Giddings and Hawkville fields. As previously disclosed, the Company expects to bring seven wells onto production by the end of the first quarter of 2023, with a pause in activity until the sales process is complete.

The Board has formed a sub-committee, led by independent directors, to lead discussions with the various stakeholders of the Company as it assesses alternatives following the conclusion of the sales process.

SUBSEQUENT EVENTS

Dividends

On January 3, 2023, the Company's board of directors (the "Board") declared a dividend of $0.0315 per SVS and PVS, and $3.15 per MVS. Payable on January 31, 2023, to shareholders of record on the close of business on January 17, 2023.

On February 1, 2023, the Company's Board declared a dividend of $0.0315 per SVS and PVS, and $3.15 per MVS. Payable on February 28, 2023, to shareholders of record on the close of business on February 14, 2023.

On February 23, 2023, it was announced that monthly dividends would be suspended beginning in March 2023, in connection with the strategic review of assets.

Completion of the Fifth Development Partnership and creation of Development Partnership Seven

On January 20, 2023, the Company redeemed redeemable non-controlling interests with a redemption value of $36,354,869. As part of this redemption, the development partnership five units with a redemption value of $2,505,631 were exchanged for 499,794 Class B non-voting units of the Company's operating subsidiary.

On January 20, 2023, the Company also formed the development partnership seven program, with 24 external limited partners and the Company's operating subsidiary as a limited partner and the general partner. The intention of the program is to finance the drilling and completion of five wells, with external partners funding approximately 60% and the Company funding 40%. The Company raised $34,262,236 from external limited partners of which $4,946,981 was raised from officers and directors of the Company.

Strategic Review of Assets

On February 23, 2023, the Company announced that the Board had commenced a strategic review of its assets. The Company is seeking to facilitate a timely and orderly response to unsolicited inquiries by other upstream oil and gas companies who have expressed interest in acquiring various assets of the Company.

Director Resignation

On March 3, 2023, the Company announced that Darren Tangen had resigned from its Board, including its Compensation, Audit and Operations and Reserves Committees, effective March 2, 2023. In connection with the resignation, James Russo was appointed as a member of the Board as well as a member of the Compensation, Audit and Operations and Reserves Committees to fill the vacancy created by Darren Tangen's resignation.

Engagement of Stephens Inc.

On March 8, 2023, the Company announced that it had engaged Stephens Inc. as its financial advisor to pursue an asset sale for various strategic, high producing assets recently developed and proven by the Company. Proceeds of such sale are expected to retire existing liabilities as well as place additional capital on the Company's balance sheet.

Debt Amendments and Covenant Waiver`

In March 2023, the Company received a waiver of all covenants on the Corporate Credit Facility until July 1, 2023, and received a waiver on certain covenants on the ABS Facility until July 1, 2023. The Company also received an extension on the initial maturity date of Tranche 1 under the ABS Facility until July 1, 2023. In the absence of a covenant waiver, a breach of the covenant would result in the Corporate Credit Facility and/or ABS Facility to be due on demand.

Additional Information

Additional information relating to the Company is contained in the Company's Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial information required by Item 8 is located beginning on page F-1 of this Annual Report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Management of the Company, including the Chief Executive Officer ("**CEO**") and Chief Financial Officer ("**CFO**"), have evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the year covered by this Form 10-K. The term "disclosure controls and procedures" means controls and other procedures established by the Company that are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, our management conducted an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period ended December 31, 2022, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer have concluded that during the period covered by this report, our disclosure controls and procedures were effective as of December 31, 2022.

The Company, including its CEO and CFO, does not expect that its internal controls and procedures will prevent or detect all error and all fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2022, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework* (2013). We have evaluated the effectiveness of our internal control over financial reporting as of the end of the period covered by this report, with the participation of our CEO and CFO, as well as other key members of our management. Based on this assessment, management concluded that, as of December 31, 2022, the Company's internal control over financial reporting was effective.

Attestation Report of the Registered Public Accounting Firm

This Annual Report does not include an attestation report of the Company's registered independent public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered independent public accounting firm as the Company qualifies as an "emerging growth company" under the Jumpstart Our Business Start-ups Act of 2012.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in the Company's 2023 Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in the Company's 2023 Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

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

The information required in response to this item will be set forth in the Company's 2023 Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

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

The information required in response to this item will be set forth in the Company's 2023 Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required in response to this item will be set forth in the Company's 2023 Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

The financial statements listed in the accompanying index (page F-1) are filed as part of this Annual Report.

(a)(2) Financial Statement Schedules

Schedules have been omitted because they are not applicable, not material or because the information is included in the consolidated financial statements or the notes thereto.

(a)(3) Exhibits

The exhibits are incorporated by reference from the Exhibit Index attached hereto.

ITEM 16. FORM 10-K SUMMARY

None.

EXHIBIT INDEX

Exhibit No.	Description of Exhibit
2.1*	Business Combination Agreement amongst HB2 Origination, LLC, Alpine Summit Energy Investors, Inc., Red Pine Petroleum Ltd., Alpine Summit Energy Partners Finco, Inc., and Red Pine Petroleum Subco Ltd., dated April 8, 2021
3.1*	Amended Articles of Alpine Summit Energy Partners, Inc.
3.2*	Notice of Articles of Alpine Summit Energy Partners, Inc.
3.3*	Quorum Policy of Alpine Summit Energy Partners, Inc.
4.1*	Description of Registrant's Securities
10.1*	Alpine Summit Funding, LLC, $80,000,000 Series 2022-1 Floating Rate Oil & Gas Asset-Backed Notes due April 2023 Note Purchase Agreement, dated April 29, 2022
10.2*	Asset Purchase Agreement dated April 29, 2022, by and between Alpine Summit Funding, LLC, and HB2 Origination, LLC
10.3*	Amended and Restated Indenture between Alpine Summit Funding, LLC, as Issuer, and UMB Bank, N.A., as Indenture Trustee, as Paying Agent and as Securities Intermediary, dated as of September 12, 2022
10.4*	First Supplemental Indenture, dated as of March 23, 2023, but made effective as of December 31, 2022, between Alpine Summit Funding, LLC and UMB Bank, N.A., as Indenture Trustee
10.5*♦	Side Letter Agreement, dated as of March 23, 2023, among Alpine Summit Funding Holdings, LLC, Alpine Summit Energy Partners, Inc., HB2 Origination, LLC, Ironroc Energy Partners LLC, Ageron Ironroc Energy, LLC and the noteholders
10.6*	Alpine Summit Funding, LLC, $55,000,000 Series 2022-2 Floating Rate Oil & Gas Asset-Backed Notes due September 2023 Note Purchase Agreement, dated September 12, 2022
10.7*	Asset Purchase Agreement dated September 12, 2002, by and between Alpine Summit Funding, LLC, and HB2 Origination, LLC
10.8*	Amended and Restated Management Services Agreement between Alpine Summit Funding, LLC, as Issuer, and HB2 Origination, LLC, as Manager, dated September 12, 2022
10.9*	$65,000,000 First Amended and Restated Credit Agreement for Reducing Revolving Credit Facility dated September 30, 2022, between HB2 Origination, LLC, as Borrower, and Bank 7, as Lender
10.10*	Omnibus Waiver Agreement dated March 10, 2023, between HB2 Origination, LLC, as Borrower, and Bank7, as Lender
10.11*	Amended and Restated Omnibus Waiver Agreement dated March 21, 2023, between HB2 Origination, LLC, as Borrower, and Bank7 as Lender
10.12*	Extension Agreement, effective as of March 21, 2023, by and between HB2 Origination, LLC, as Borrower, and Bank7, as Lender
10.13*#	Alpine Summit Energy Partners, Inc. 2021 Stock and Incentive Plan
10.14*#	Alpine Summit Energy Partners, Inc. Deferred Share Unit Plan
10.15*#	Form of Stock Option Award Agreement
10.16*#	Form of Restricted Stock Unit Award Agreement

10.17*#	Form of Deferred Share Unit Grant Letter
10.18*#	Form of Indemnity Agreement between Alpine Summit Energy Partners, Inc. and its directors and officers as of September 7, 2021
10.19*#	Member Services Agreement by and between HB2 Origination, LLC, and Craig Perry dated May 7, 2022
10.20*#	Member Services Agreement by and between HB2 Origination, LLC, and William Wicker dated May 7, 2022
10.21*#	Member Services Agreement by and between HB2 Origination, LLC, and Michael McCoy dated September 7, 2021

Exhibit No.	Description of Exhibit
10.22*#	Member Services Agreement by and between HB2 Origination, LLC, and Christopher Nilan dated May 7, 2022
10.23*#	Member Services Agreement by and between HB2 Origination, LLC, and Travis Reagan Brown, dated May 7, 2022
10.24*#	Employment Agreement entered into as of September 7, 2021, by and between HB2 Origination, LLC, and Darren Moulds
10.25*#	Employment Agreement entered into as of September 7, 2021, by and between HB2 Origination, LLC, and Chrystie Holmstrom
10.26*#	Form of Restrictive Covenant Agreement for Officers
14.1*	Code of Ethics for Alpine Summit Energy Partners, Inc.
21.1*	Subsidiaries of Alpine Summit Energy Partners, Inc.
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent Letter of Independent Reserves Evaluators
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of The Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of The Sarbanes-Oxley Act of 2002
32.1‡	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of The Sarbanes-Oxley Act of 2002
32.2‡	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of The Sarbanes-Oxley Act of 2002
99.1*	Summary Reserve Report
101.INS	Inline XBRL Instance Document–the instance document does not appear in the Interactive Data File as its XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Taxonomy Extension Schema Documen
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Filed herewith.

‡ Document has been furnished, is not deemed filed and is not to be incorporated by reference into any of the Company's filings under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, irrespective of any general incorporation language contained in any such filing.

\# Management contract, compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K

♦ Certain identified information has been omitted from this exhibit because it is both (1) not material and (2) the type that the Company treats as private or confidential.

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 27, 2023.

ALPINE SUMMIT ENERGY PARTNERS, INC.

/s/ Craig Perry
By: Craig Perry
Title: Chief Executive Officer
(Principal Executive Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Craig Perry and Craig Perry, jointly and severally, his or her attorney-in-fact, each with the full power of substitution, for such person, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might do or could do in person hereby ratifying and confirming all that each of said attorneys-in-fact and agents, or his or her substitute, may do or cause to be done by virtue hereof.

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 capacities indicated and on the dates indicated.

Name and Signature	Title	Date
/s/ Craig Perry Craig Perry	Chief Executive Officer and Director (Principal Executive Officer)	March 27, 2023
/s/ Darren Moulds Darren Moulds	Chief Financial Officer (Principal Financial and Accounting Officer)	March 27, 2023
/s/ James Russo James Russo	Director	March 27, 2023
/s/ Stephen Schaefer Stephen Schaefer	Director	March 27, 2023
/s/ Porter Collins Porter Collins	Director	March 27, 2023
/s/ Agenia Clark Agenia Clark	Director	March 27, 2023

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of
Alpine Summit Energy Partners, Inc.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Alpine Summit Energy Partners, Inc. (formerly Red Pine Petroleum Ltd.) (the “Company”) as of December 31, 2022 and 2021, and the related consolidated statements of operations and comprehensive income (loss), changes in shareholders’ deficiency and cash flows for each of the two years in the period ended December 31, 2022, and the related notes to the consolidated financial statements.

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its consolidated operations and its cash flows for each of the two years then ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has a net working capital deficiency of $162,980,101, which raises substantial doubt about its ability to continue as a going concern. Management's plans in regards to this matter is described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

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

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

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ WEAVER AND TIDWELL, L.L.P.

We have served as the Company's auditor since 2021.

Houston, Texas
March 24, 2023

ALPINE SUMMIT ENERGY PARTNERS, INC. (FORMERLY RED PINE PETROLEUM LTD.)
CONSOLIDATED BALANCE SHEETS

As at December 31 (in U.S. dollars, except share amounts)

	Notes	2022	2021
ASSETS			
Current assets:			
Cash and cash equivalents		$ 7,123,068	$ 8,622,815
Restricted cash	2	3,375,395	-
Accounts receivable, net	3	26,466,208	18,797,635
Derivative assets	18	2,019,600	-
Prepaid expenses		1,075,697	535,474
Total current assets		**40,059,968**	**27,955,924**
Oil and natural gas properties, full-cost method:			
Evaluated		347,541,801	110,155,103
Unproved and unevaluated		42,866,767	24,987,312
Less: accumulated depreciation, depletion and amortization		(87,993,495)	(25,911,025)
Oil and natural gas properties, net	4	**302,415,073**	**109,231,390**
Other noncurrent assets:			
Operating lease assets	5	548,963	434,488
Derivative assets	18	1,057,479	-
Total assets		**$ 344,081,483**	**$ 137,621,802**
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
Current liabilities			
Accounts payable and accrued liabilities		$ 96,432,486	$ 48,245,677
Corporate credit facility	7	41,500,000	2,200,000
Current portion of operating lease liabilities	5	210,157	119,371
Current portion of long-term debt (net)	7	60,226,919	7,059,834
Accrued liability for automatic share purchase plan	11	4,670,507	-
Derivative liabilities	18	-	6,479,508
Total current liabilities		**203,040,069**	**64,104,390**
Long-term debt, net	8	48,678,708	16,139,307
Operating lease liabilities	5	401,734	389,218
Asset backed preferred instrument	8	-	18,687,351
Derivative liabilities	18	-	13,901,672
Asset retirement obligations	6	458,078	431,704
Deferred income tax liability	15	-	1,928,319
Total liabilities		**$ 252,578,589**	**$ 115,581,961**
Commitments and contingencies	19		
Redeemable non-controlling interest	9	**$ 107,583,737**	**$ 46,552,839**
SHAREHOLDERS' DEFICIENCY			
Share capital - Subordinate Voting Shares *Authorized unlimited shares without par value. Issued and outstanding are 33,956,073 and 32,535,731 as at December 31, 2022 and 2021, respectively.*	11	47,595,028	41,989,020
Share capital - Multiple Voting Shares *Authorized unlimited shares without par value. Issued and outstanding are 8,380 and 10,336 as at December 31, 2022 and 2021, respectively.*	11	1,051,546	1,296,914
Share capital - Proportionate Voting Shares *Authorized unlimited shares without par value. Issued and outstanding are 15,947 as at December 31, 2022 and 2021.*	11	128,213	128,213
Additional paid-in capital		36,436,307	40,252,848
Accumulated deficit		(76,210,173)	(83,638,308)
Shareholders' equity (deficit) attributable to the Company		**9,000,921**	**28,687**

Non-controlling interest	10	(25,081,764)	(24,541,685)
Total Shareholders' Deficiency		**$ (16,080,843)**	**$ (24,512,998)**
TOTAL LIABILITIES, REDEEMABLE NON-CONTROLLING INTEREST AND SHAREHOLDERS' DEFICIENCY		**$ 344,081,483**	**$ 137,621,802**

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

ALPINE SUMMIT ENERGY PARTNERS, INC. (FORMERLY RED PINE PETROLEUM LTD.)
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

For the years ended December 31 (in U.S. dollars, except share and per share amounts)

	Notes	2022	2021
REVENUES			
Oil and gas revenues	14	$ 195,648,957	$ 70,796,790
Gain / (loss) on derivative instruments, net	18	(10,023,495)	(33,525,453)
Total revenues		**185,625,462**	**37,271,337**
OPERATING EXPENSES			
Production costs and transportation		41,495,709	12,087,223
General and administrative	21	26,090,160	25,021,117
Depreciation, depletion, and amortization	4	62,082,471	23,497,715
Asset retirement obligation accretions	6	43,756	24,209
Total operating expenses		**129,712,096**	**60,630,264**
OPERATING INCOME (LOSS)		**55,913,366**	**(23,358,927)**
OTHER INCOME (EXPENSE)			
Finance and interest expense	20	(13,428,333)	(5,727,544)
Acquisition costs	1	-	(1,567,967)
Total other income (expense)		(13,428,333)	(7,295,511)
INCOME (LOSS) BEFORE INCOME TAXES		**42,485,033**	**(30,654,438)**
Income tax provision (benefit)	15	(1,928,319)	1,928,319
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)		**44,413,352**	**(32,582,757)**
NET INCOME ATTRIBUTABLE TO REDEEMABLE NON-CONTROLLING INTEREST	9	33,796,021	13,091,908
NET INCOME (LOSS) ATTRIBUTABLE TO NON-CONTROLLING INTEREST	10	3,189,196	(13,330,237)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO THE COMPANY		**$ 7,428,135**	**$ (32,344,428)**
Earnings (loss) per SVS and PVS, and MVS on an as-converted basis: (Note 13)			
Basic		**$ 0.22**	$ (0.76)
Diluted		**$ 0.20**	$ (0.76)
Weighted average number of shares per SVS and PVS, and MVS on an as-converted basis: (Note 13)			
Basic		**34,453,696**	42,596,264
Diluted		**53,586,327**	42,596,264

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

ALPINE SUMMIT ENERGY PARTNERS, INC. (FORMERLY RED PINE PETROLEUM LTD.)
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' DEFICIENCY

As at and for the years ended December 31 (in U.S. dollars, except share and per share amounts)

	Notes	Total Share Capital	Additional Paid In-Capital	Accumulated Deficit	**Total shareholders' equity attributable to the Company**	Non-controlling interests	**Total Equity**
		Note 11					
Balance as at January 1, 2021		$ 37,097,376	$ 3,721,683	$ (39,408,964)	**$ 1,410,095**	$ -	**$ 1,410,095**
Issuance of member units for cash	11	8,044,700	-	-	**8,044,700**	-	**8,044,700**
Issuance of member units exchanged for notes	11	3,475,000	-	-	**3,475,000**	-	**3,475,000**
Issuance of member units for oil and gas properties	11	3,499,995	-	-	**3,499,995**	-	**3,499,995**
Issuance of member units to contractors	11	9,073,228	-	-	**9,073,228**	-	**9,073,228**
Redemption of member units	8	(8,680,786)	-	(11,884,916)	**(20,565,702)**	-	**(20,565,702)**
Issuance of member units exchanged for notes	11	2,300,000	-	-	**2,300,000**	-	**2,300,000**
Allocation of opening non-controlling interest	10	(18,721,276)	30,208,275	-	**11,486,999**	(11,486,999)	**-**
Shares issued for cash, net of issuance costs of $247,218	1	5,499,832	-	-	**5,499,832**	-	**5,499,832**
PVS issued for cash	1	128,213	-	-	**128,213**	-	**128,213**
Shares issued on reverse recapitalization	1	1,697,865	-	-	**1,697,865**	-	**1,697,865**
Stock based compensation	12	-	5,405,548	-	**5,405,548**	-	**5,405,548**
Development partnership redemption for Origination Member Units	10	-	917,342	-	**917,342**	275,551	**1,192,893**
Net loss		-	-	(32,344,428)	**(32,344,428)**	(13,330,237)	**(45,674,665)**
Balance as at December 31, 2021		**$ 43,414,147**	**$ 40,252,848**	**$ (83,638,308)**	**$ 28,687**	**$ (24,541,685)**	**$(24,512,998)**

Settlement of RSUs	11, 12	9,685,555	(9,685,555)	-	**-**	-	**-**
Repurchase of SVS for cancellation	11	(4,324,915)	-	-	**(4,324,915)**	-	**(4,324,915)**
Change in NCI ownership	10	-	1,445,850	-	**1,445,850**	(1,445,850)	**-**
Automatic share purchase plan	11	-	(4,670,507)	-	**(4,670,507)**	-	**(4,670,507)**
Stock based compensation	12	-	10,197,720	-	**10,197,720**	-	**10,197,720**
Development partnership redemption for Origination Member Units	10	-	11,312,710	-	**11,312,710**	4,269,258	**15,581,968**
Dividends declared	10, 11	-	(12,416,759)	-	**(12,416,759)**	(6,552,683)	**(18,969,442)**
Net income		-	-	7,428,135	**7,428,135**	3,189,196	**10,617,331**
Balance as at December 31, 2022		**$ 48,774,787**	**$ 36,436,307**	**$ (76,210,173)**	**$ 9,000,921**	**$ (25,081,764)**	**$(16,080,843)**

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

ALPINE SUMMIT ENERGY PARTNERS, INC. (FORMERLY RED PINE PETROLEUM LTD.)
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (in U.S. dollars)

	Notes	2022	2021
Cashflows from operating activities			
Net income (loss)		$ 44,413,352	$ (32,582,757)
Adjustments to reconcile net income (loss) to cashflows from operating activities:			
Depletion and depreciation	4	62,082,471	23,497,715
Amortization of operating lease asset	5	121,088	64,559
Asset retirement obligation accretion expense	6	43,756	24,209
Share-based compensation	12	10,197,720	14,478,776
Amortization of deferred financing costs	7	5,199,882	1,058,759
Unrealized (gain) / loss on derivative instruments	18	(26,246,352)	15,859,796
Deferred income tax expense (benefit)	15	(1,928,319)	1,928,319
Margin returns/(calls) on derivative instruments, net	18	2,788,093	-
Changes in operating assets and liabilities	22	(3,769,555)	8,667,404
Cashflows used in investing activities		**92,902,136**	**32,996,780**
Cashflows from investing activities			
Capital expenditures on oil and natural gas properties	4	(212,210,813)	(56,678,478)
Cashflows from investing activities		**(212,210,813)**	**(56,678,478)**
Cashflows from financing activities			
Issuance of shares for cash, net of issuance costs		-	13,672,745
Cash acquired on acquisition	1	-	396,173
Proceeds from Redeemable NCI	9	53,728,933	41,042,693
Redemption and distributions to Redeemable NCI	9	(10,369,504)	(6,388,870)
Proceeds from credit facility draws	7	108,000,000	2,200,000
Proceeds from promissory notes	8	-	3,375,000
Repayment on credit facility	7	(68,700,000)	-
Repayment of promissory notes	8	-	(2,025,000)
Repayment of asset backed preferred notes	8	(18,687,351)	(4,735,700)
ABS Facility issuance, net of issuance costs	7	130,761,336	-
Payment on ABS Facility	7	(25,017,323)	-
Other long term debt repayment	7	(25,237,409)	(18,122,088)
Dividends on common shares and noncontrolling interest	10, 11	(18,969,442)	-
Cash used for common share repurchases	11	(4,324,915)	-
Cashflows provided by financing activities		**121,184,325**	**29,414,953**
Net increase/(decrease) in cash and cash equivalents and restricted cash		1,875,648	5,733,255
Cash, cash equivalents and restricted cash, beginning of year		8,622,815	2,889,560
Cash, cash equivalents and restricted cash, end of year		**$ 10,498,463**	**$ 8,622,815**

Refer to Note 22 for supplementary cash flow information.

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

1. GENERAL

Description of Business

Alpine Summit Energy Partners, Inc. (formerly Red Pine Petroleum Ltd. ("Red Pine") (the "Company" or "Alpine Summit") was incorporated on July 30, 2008 under the Business Corporations Act (British Columbia) ("BCBCA"). On April 8, 2021, the Company entered into a Business Combination Agreement ("BCA") pursuant to which it agreed to complete the BCA with HB2 Origination LLC ("Origination") and changed its name to "Alpine Summit Energy Partners, Inc." upon completion of the BCA (described below).

The Company is engaged in oil and natural gas development, production, acquisition, and exploration activities in Texas through its controlled subsidiary Origination. The Company's operating activities are mainly focused in the Austin Chalk and Eagle Ford formations in the Giddings Field, as well as the Hawkville Field.

Reverse Takeover Agreement

On April 8, 2021, the Company, Origination, Alpine Summit Energy Partners Finco, Inc. (“Finco”), Red Pine Petroleum Subco Ltd. (“Subco”) and Alpine Summit Energy Investors, Inc. (“Blocker”) entered into the BCA pursuant to which the parties agreed to complete a series of transactions to effect a combination between the Company (through its predecessor Red Pine Petroleum Ltd.) and Origination and that resulted in a reverse take-over (“RTO”) of the Company by the members of Origination.

The principal steps of this transaction were as follows:

(a) Finco issued subscription receipts (the "Subscription Receipts") for gross proceeds of approximately Canadian Dollars ("CAD") $7,500,000 (the "Finco Financing"), as described below.

(b) immediately prior to the closing of the BCA:

   (i) the Company amended its articles to (A) reclassify its common shares as Subordinate Voting Shares ("SVS"), (B) create a new class of Multiple Voting Shares ("MVS") and a new class of Proportionate Voting Shares ("PVS"), and (C) change its name from "Red Pine Petroleum Ltd." to "Alpine Summit Energy Partners, Inc.";

   (ii) each outstanding membership unit of Origination was split into three membership units of Origination ("Origination Member Units");

   (iii) the Subscription Receipts converted into shares of Finco, with each subordinate voting subscription receipt converting to one Class A share of Finco, and each holder of a multiple voting subscription receipt converting to one Class B share of Finco.

(c) on closing of the BCA:

   (i) the Company, Finco and Subco completed a three-cornered amalgamation under the BCBCA pursuant to which all Finco shareholders (including former holders of the Subscription Receipts) exchanged their (A) Class A shares of Finco for SVS; and (B) Class B shares of Finco for MVS, as applicable, in each case on a one-for-one basis, and Finco and Subco amalgamated, with the resulting entity ("Amalco") to continue as a wholly-owned subsidiary of the Company;

   (ii) Amalco wound up into the Company, and the assets of Amalco (which consist of the funds invested by the holders of the Subscription Receipts, net of expenses) transferred to the Company by operation of law;

   (iii) certain U.S. holders of Origination Member Units (other than Blocker) contributed their Origination Member Units to the Company in exchange for MVS, on a one hundred Origination Member Units for one MVS basis;

   (iv) certain non-U.S. holders of Origination Member Units contributed their Origination Member Units to the Company in exchange for SVS, on a one Origination Member Unit for one SVS basis, subject to adjustment for any applicable withholding taxes;

(v) the Origination Member Units held by Blocker (the "Blocker Shares) were contributed to the Company in exchange for SVS on a one Blocker Share for three SVS basis;

(vi) a related party, being an officer, director and shareholder of Origination pre-closing of the BCA, and of Alpine Summit post-closing of the BCA, subscribed for 15,947.292 PVS carrying voting rights that would, in the aggregate, represent approximately 32.2% of the voting rights of the Company upon completion of the BCA on a fully diluted basis for a purchase price equivalent to their estimated fair market value of $128,213;

(vii) the Company used certain proceeds from the Finco Financing and the Origination Member Units received by it to subscribe for Blocker Shares, following which the proceeds of Finco Financing received by Blocker were contributed to Origination in exchange for Origination Member Units; and

(viii) Origination Member Units held by Blocker were re-designated as Class A voting units of Origination and Origination Member Units held by other remaining members of Origination were re-designated as Class B non-voting units of Origination.

The Finco Financing

On August 18, 2021, Finco completed a brokered private placement of the Subscription Receipts, consisting of an aggregate of 161,976 subordinate voting subscription receipts at a subscription price of CAD$4.01 per subscription receipt and 17,057 multiple voting subscription receipts at a subscription price of CAD$401.29 per subscription receipt for aggregate gross proceeds of approximately CAD$7,500,000 (net proceeds of US$5,499,832). Finco is a special purpose British Columbia company incorporated solely for the purpose of the Finco Financing.

The Finco Financing was completed pursuant to the terms of an agency agreement dated August 18, 2021 among Finco, the Company and Eight Capital ("Agent"), as lead agent and sole bookrunner. The Subscription Receipts are governed by the terms of the subscription receipt agreement (the "Subscription Receipt Agreement") dated August 18, 2021 among Finco, the Agent and Odyssey Trust Company in its capacity as subscription receipt agent.

Each subordinate voting subscription receipt and each multiple voting subscription receipt entitled the holder thereof to receive, upon automatic exchange in accordance with the terms of the Subscription Receipt Agreement, without payment of additional consideration or further act or formality on the part of the holder thereof, one Class A share of Finco and one Class B share of Finco, respectively, upon the satisfaction or waiver of the escrow release conditions at or before the escrow release deadline. Each Class A share of Finco was exchanged for one SVS and each Class B share of Finco was exchanged for one MVS upon completion of the BCA.

In connection with the Finco financing, the Agent was entitled to receive a cash commission of $21,002 and an advisory fee of $156,381 (collectively, the "Agent's Fees"). On closing of the Finco Financing, the Agent received payment of 50% of the Agent's Fees. The remaining 50% of the Agent's Fees were paid to the Agent upon the satisfaction of the escrow release conditions.

Reverse Takeover

On September 7, 2021, the Company completed the BCA (as described above). As a result, the former shareholders of Origination acquired control of the combined Company and, thereby the transaction constitutes a reverse recapitalization of Red Pine by Origination. The BCA is considered a purchase of the Red Pine's net assets by Origination.

As Red Pine did not qualify as a business in accordance with Accounting Standards Codification ("ASC") *Topic 805 - Business Combinations*, the BCA does not constitute a business combination. The BCA was accounted for as a reverse recapitalization as the equivalent of Origination issuing its equity for the net assets of the Company, accompanied by a recapitalization. Accordingly, all historical financial information presented in these consolidated financial statements represents the accounts of Origination and its wholly owned subsidiaries "as if" Origination was the predecessor to the Company. The shares and net loss per common share, prior to the BCA, have been adjusted to reflect the share exchange ratios established in the BCA.

As a part of the reverse takeover, the Company issued 534,384 SVS on September 7, 2021, for total consideration of $1,697,865 based on the Finco Financing value of CAD$4.01/SVS (US$3.18/SVS), for the Red Pine net assets, which were made up primarily of cash valued at $396,173. The difference between the fair value of the consideration issued and the net assets acquired was recorded in additional paid in capital.

Acquisition related costs of $1,567,967 were recognized as transaction costs in other income (expense) within the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021, when the costs were incurred.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements (the "financial statements") of the Company and its subsidiaries have been prepared in conformity with accounting principles generally accepted in the United States of America ("US GAAP"). Amounts are stated in US dollars unless otherwise noted.

The Company historically prepared its consolidated financial statements under International Financial Reporting Standards. For the year ended and as at December 31, 2022 the Company transitioned to US GAAP and applied US GAAP retrospectively.

Basis of Measurement

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the financial statements. In determining these estimates, management makes subjective and complex judgments that may require assumptions about matters that are inherently uncertain. The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Estimates and assumptions that, in the opinion of the Company's management, are significant include the estimation of oil and natural gas reserves and depletion (Note 2 below), the redemption value of redeemable non-controlling interests (Note 2 below and Note 9), determination of whether long-lived assets are impaired (Note 2 below), valuation of asset retirement obligations (Note 2 below and Note 6), and deferred tax assets/liabilities (Note 2 below and Note 15). The Company bases its estimates and judgments on historical experience and on various other assumptions and information believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be predicted with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained, or if the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of these financial statements.

Going Concern

The financial statements have been prepared assuming that the Company will continue as a going concern, which contemplates continuity of operations, realization of assets, and liquidation of liabilities in the normal course of business.

As at December 31, 2022 the Company had a working capital deficit of $162,980,101, reflecting a significant increase in outstanding accounts payable and accrued liabilities as well as borrowings, due to the Company's increased capital expenditures on oil and natural gas properties. As a result, the Company does not currently have the cash resources to meet its current liabilities for the next twelve months. These factors raise substantial doubt about the Company's ability to continue as a going concern.

The Company's ability to continue as a going concern is dependent on its ability to generate sufficient cash flows from operations, as well as its ability to obtain financing via an asset sale and/or the issuances of debt and/or equity in the short term. While the Company believes it has sufficient forecasted funds to meet foreseeable obligations, there can be no assurance that the Company will be successful in its efforts to raise additional funds in the short term and its ability to generate sufficient operating cash flows.

Due to these factors, the Company may be unable to continue as a going concern. The financial statements do not include any adjustments related to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might be necessary should the Company be unable to continue as a going concern, and such adjustments could be material.

Basis of Consolidation

Subsidiaries

The financial statements include the accounts of the Company and its consolidated subsidiaries, after the elimination of intercompany transactions and balances. The Company consolidates all entities that it controls either through a majority voting interest or as the primary beneficiary of variable interest entities ("VIEs").

The Company evaluates (1) whether it holds a variable interest in an entity, (2) whether the entity is a VIE, and (3) whether the Company's involvement would make it the primary beneficiary.

The assessment of whether the entity is a VIE is generally performed qualitatively, which requires judgment. These judgments include: (a) determining whether the equity investment at risk is sufficient to permit the entity to finance its activities without additional subordinated financial support, (b) evaluating whether the equity holders, as a group, have the characteristics of a controlling financial interest, (c) determining whether two or more parties' equity interests should be aggregated, (d) determining whether the equity investors have proportionate voting rights to their obligations to absorb losses or rights to receive returns from the entity, and (e) if disproportionate voting rights are identified, whether substantially all of the investee's activities are on behalf of an investor that has disproportionately few voting rights. Significant judgements involve the analysis of the risks and rewards that the VIE's operations generate and the nature of the Company's involvement with and interest in the VIE, including the form of the Company's ownership interest, representation in an entity's governance, and ability to participate in making decisions.

For entities that are determined to be VIEs, the Company consolidates those entities where it has concluded it is the primary beneficiary. The primary beneficiary is defined as the variable interest holder with (a) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and (b) the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the VIE. In evaluating whether the Company is the primary beneficiary, the Company evaluates its economic interests in the entity held either directly or indirectly by the Company, and its ability to control the VIEs through arrangements such as general partnership interests or contracts.

The Company's consolidated VIEs consist of its controlled subsidiary, Origination, as its control over Origination is contractually provided and not granted via the equity interest. Origination, through its subsidiaries, holds the Company's main operations, including external financing. Some of Origination's drilling programs are structured through limited partnerships (the "Development Partnerships"), which are consolidated VIEs of Origination (see Note 9).

Under the contractual agreements with the VIEs, the Company has the power to direct activities of the VIEs and can have assets transferred out of the VIEs under its control. Therefore, the Company considers that there is no asset in any of the VIEs that can be used only to settle obligations of the VIE, except for certain assets that are designated as collateral for long term debt (Note 7).

If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity.

Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests.

Joint Arrangements

A portion of the Company's oil and natural gas business activities involve jointly controlled assets and are conducted under joint operating agreements. These consolidated financial statements reflect only the Company's proportionate share of the joint operation's controlled assets and liabilities it has incurred, its share of any liabilities jointly incurred with other joint interest partners, income from the sale or use of its share of the joint operation's output, together with its share of expenses incurred by the joint operation and any expenses it incurs in relation to its interest and its share of production in such activities.

Segment Reporting

The Company operates in a single operating and reportable segment. Operating segments are defined as components of a public entity for which separate financial information is regularly reviewed by the chief operating decision maker in deciding how to allocate resources and assess performance. The Company's chief operating decision maker allocates resources and assesses performance based upon financial information at the Company level. The Company's operations are primarily conducted in, and its assets are primarily located in, the United States of America. The Company's revenues are entirely generated in the United States of America.

Functional and Presentation Currency

These financial statements are presented in US dollars. The functional currency of the Company and its individual subsidiaries is the US dollar, which represents the primary economic environment in which the entities operate.

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting for the remeasurement of monetary assets and liabilities are included in general and administrative expenses in the consolidated statements of operations and comprehensive income (loss) in the period in which they arise.

Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased (Note 18).

Restricted Cash

Cash and cash equivalents that are restricted as to the withdrawal or usage, in accordance with specific arrangements, are presented as restricted cash. The amount of restricted cash as of December 31, 2022 is $3,375,395 (December 31, 2021 - $nil), reflecting the interest reserve account maintained in connection with the asset backed securitization facility (Note 7).

Accounts Receivable, Net

The accounts receivable are primarily receivables from crude oil, natural gas, and natural gas liquids customers and joint interest owners. Oil and natural gas sales are normally collected by the Company between 30 and 60 days from deliveries. Joint interest receivables are typically collected within 30 to 90 days of the joint interest bill being issued to the partner.

Accounts receivable, net are recorded at amortized cost. Management evaluates all accounts periodically and an allowance is established based on the best facts available. Management considers historical collection data, accounts receivable aging trends, other operational trends and reasonable forecasts to estimate the collectability of receivables. The Company's accounts receivable are subject to normal industry credit risk (Note 18).

Derivatives

The Company has entered into certain financial risk management contracts in order to manage the exposure to market risks from fluctuations in commodity prices and interest rates. The Company considers all risk management contracts to be economic hedges, but has not designated its financial risk management contracts as accounting hedges and, therefore, has not applied hedge accounting. As a result, all financial risk management contracts are measured at fair value with changes in fair value recognized in income (Note 17). Transaction costs are recognized in the consolidated statements of operations and comprehensive income (loss) as incurred.

In the consolidated balance sheets, the fair values of the derivative instruments are presented as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current (Note 18).

Oil and Natural Gas Properties, Net

Oil and Natural Gas Properties

The Company uses the full-cost method of accounting for its oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, and general and administrative expenses directly related to acquisition, exploration and development activities, but does not include any costs related to production, selling or general corporate administrative activities.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized. In the years ended December 31, 2022 and 2021, there were no property sales that resulted in a significant alteration.

Depletion

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus estimates of future development costs by estimates of proved reserves quantities. Unproved and unevaluated property costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are considered proved or impaired. The Company reviews its unproved and unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization.

Upon impairment, which includes leases that have expired or have been deemed uneconomic, the costs of the unproved properties are immediately included in the depletion base.

The determination of depletion is significantly impacted by the proved reserves volumes and future development costs.

Relative volumes of reserves and production are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Impairment

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the net capitalized costs of oil and natural gas properties. The net capitalized costs are limited to the lower of unamortized costs less related deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of: (a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) any income tax effects related to the properties involved.

Any excess of the Company's net capitalized costs above the cost center ceiling is expensed as a full-cost ceiling impairment. The Company's derivative instruments are not considered in the ceiling test computations as the Company does not designate these instruments as hedges for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent on the quantities of proved reserves, the estimation of which requires substantial judgement. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the United States Securities and Exchange Commission. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost changes in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period, and a 10% discount factor is used to determine the present value of future net revenues. For the period from January through December 2022, these average oil and natural gas prices were $94.49 per Bbl and $6.25 per MMBtu, respectively. For the period from January through December 2021, these average oil and natural gas prices were $66.55 per Bbl and $3.64 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were further adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were further adjusted by property for energy content, transportation and marketing fees and regional price differentials.

During the years ended December 31, 2022 and 2021, the Company's full-cost ceiling exceeded the net capitalized costs less related deferred income taxes. As a result, the Company recorded no impairment to its net capitalized costs for those periods.

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company’s assets on its consolidated balance sheets, as well as the corresponding shareholders’ deficiency, but it has no impact on the Company’s net cash flows as reported. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company’s actual ceiling test computation and impairment analyses in future periods.

Other Impairment Estimates

Unproved and unevaluated properties are assessed periodically to determine whether they have been impaired, based on the Company's future development plans, the probability of successful development of properties and the length of time that the Company expects to hold the properties, amongst other factors.

Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the depletion base. Exploratory dry holes are included in the depletion base immediately upon determination that the well is not productive.

During the year ended December 31, 2022 and 2021, no unproved and unevaluated properties were impaired and transferred to be included in the depletion base as part of evaluated properties.

Reserves

The assessment of reported recoverable quantities of proved reserves includes estimates regarding production volumes, commodity prices, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's oil and natural gas properties, the calculation of depletion and depreciation, and the provision for asset retirement obligations.

The reserve assessment was completed by an external third-party engineering firm for the years ended December 31, 2022 and 2021 and reserves are internally updated for interim periods.

Asset Retirement Obligations

The Company recognizes asset retirement obligations ("ARO") arising from regulatory, contractual or other legal requirements to perform certain property and asset reclamation activities at the end of the respective asset life when the fair value of this obligation is determinable. These obligations consist of estimated future costs associated with the plugging and abandonment of natural gas and oil wells, and land restoration in accordance with applicable local, state and federal laws.

The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted risk-free interest rate. This discounted fair value of the ARO liability is recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the related natural gas and oil asset in property, plant and equipment, net and depleted as the reserves are produced.

In the estimation of the initial fair value of an ARO, the Company uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements including reserve lives, discount rates, and inflation rates. Given the significance of the unobservable nature of a number of the inputs, this measurement is considered Level 3 on the fair value hierarchy (Note 17).

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. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the related asset. Accretion, reflecting the increases in the ARO liability due to the passage of time is recognized as part of operating expenses within the consolidated statements of operations and comprehensive income (loss) (Note 6).

Leases

The Company assesses whether a contract is or contains a lease, at the inception of a contract. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The Company recognizes a right-of-use ("ROU") asset and a corresponding lease liability with respect to lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less). For such short-term leases, the Company recognizes the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. The Company also made the accounting policy election to not separate lease and non-lease components for its real estate leases.

The lease liability is initially measured at the present value of the unpaid lease payments at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, the Company uses its incremental borrowing rate. Subsequently, the lease liability is measured using the effective interest method, by increasing the carrying amount to reflect accretion on the lease liability and by reducing the carrying amount to reflect the lease payments made.

The ROU asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for lease payments made at or before the lease commencement date, plus any initial direct costs incurred less any lease incentives received.

For operating leases, the Company records the amortization of the ROU assets and the accretion of the lease liabilities as a single lease cost on a straight-line basis over the lease term.

The measurement of the lease liabilities and ROU assets requires the use of judgment and estimates which are applied in determining whether an arrangement contains a lease, determining the lease term, appropriate discount rate, and whether there are any indicators of impairment for ROU assets.

Revenue from Contracts with Customers

The Company enters into contracts with customers to sell its oil, natural gas and natural gas liquids. Revenue from these contracts is recognized when the Company's performance obligations are satisfied, which generally occurs with the transfer of the control to the customer, and when collectability is reasonably assured. The transfer of control usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer (often at terminals, pipelines, or other transportation methods). The Company evaluates creditworthiness on an individual customer basis prior to entering into a sales contract and throughout the contract duration (Note 18).

The sales contracts range from short term to long term contracts that are variable-priced and based on actual quantities delivered each period. The transaction price includes variable consideration as product pricing is based on published market prices and adjusted for contract specified differentials such as quality, energy content and transportation. Determining the variable consideration does not require significant judgment and the Company engages third party sources to validate the estimates.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606 – Revenue from Contracts with Customers (“ASC 606”). The expedient applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, the Company considers if it obtains control of the product delivered or services provided, which is indicated by the Company having the primary responsibility for the delivery of the product or rendering of the service, having the ability to establish prices or having inventory risk.

If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis.

Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products.

Share Based Compensation

The Company grants share purchase options, which are classified as equity settled awards. The fair value of each option granted by the Company are estimated using the Black-Scholes option pricing model and are recognized into general and administrative expense over the vesting period of the options.

The Company has also issued restricted share units (“RSUs”) and deferred share units (“DSUs”) which are both accounted for as equity classified awards. The Company’s RSUs and DSUs grants are valued using the intrinsic value method, utilizing the closing share price on the day before the grant and are recognized into general and administrative expense over the vesting period for each grant (Note 12).

In all cases for these awards, the Company estimates forfeitures and updates this estimate over the vesting period of the awards.

Income Taxes

Income tax expense comprises current and deferred tax. The expense is recognized in net income (loss) except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income (loss).

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Each reporting period, the Company reviews its deferred tax assets for the possibility they will not be realized. A valuation allowance will be recorded if it is more likely than not that a deferred tax asset will not be realized.

The benefits of uncertain tax positions that the company has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. Significant judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict. The Company did not have any uncertain tax positions during the periods presented in these financial statements.

Interest and penalties are recognized in finance expense and income tax expense, respectively. For the fiscal years ended December 31, 2022 and 2021, the Company did not incur interest and penalties related to income taxes.

Non-Controlling Interests

Non-controlling interests ("NCI") represent ownership interest in consolidated subsidiaries which are not owned, directly or indirectly, by the Company. The portion of equity not owned by the Company in such entities is reflected as NCI within the equity section of the consolidated balance sheets, and the share of income/(loss) attributable to NCI is shown as a component of net income/(loss) in the consolidated statements of operations and comprehensive income (loss). Changes to the parent company's ownership that do not result in a loss of control are accounted for as equity transactions.

Redeemable Non-controlling Interests

Non-controlling interests with redemption features that are not solely within the control of the Company are considered redeemable non-controlling interests. The Company's redeemable non-controlling interests ("Redeemable NCI") reflects the development partnership units that are not held by the Company either directly or indirectly, and which contain certain redemption rights, as described in Note 9.

The Redeemable NCI is classified in temporary equity that is reported between liabilities and shareholders' deficiency on the consolidated balance sheets and is initially recognized at its issuance date fair value. Subsequently, the Redeemable NCI is adjusted each reporting period for the net income (or loss) attributable to the Redeemable NCI interests. Further measurement adjustments are made to adjust the Redeemable NCI to the higher of the redemption value or the carrying value each reporting period.

The measurement adjustments to the redemption value are recognized through accumulated deficit and are reflected in the attribution of net income (loss) between the NCI holders, the common shareholders of the Company and the Redeemable NCI holders, such that an increase in the redemption value over the carrying value would increase the net income attributed to the Redeemable NCI.

The redemption value is calculated based on future net present values of the oil and gas reserves of the related development partnership, subject to a fixed discount rate.

Adoption of New Accounting Standards

Accounting Standards Update ("ASU") 2019-12, *Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes* was issued in December 2019. ASU 2019-12 simplifies the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance. The Company adopted ASU 2019-12 effective January 1, 2021. The adoption of ASU 2019-12 did not have a material impact on the Company's operating results, financial position or disclosures.

ASU 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity* was issued in August 2020. The update simplifies the accounting for certain financial instruments with both liability and equity characteristics and is effective for smaller reporting companies for fiscal years beginning after December 15, 2023, with early adoption permitted. The Company early adopted ASU 2020-06 effective January 1, 2021. The adoption of ASU 2020-06 did not have a material impact on the Company's operating results, financial position or disclosures.

ASU 2020-04, *Reference Rate Reform (Topic 848)*, was issued in March 2020 in response to the risk of cessation of the London Interbank Offered Rate (LIBOR). This amendment provides optional expedients and exceptions for applying generally accepted accounting principles to contracts, hedging arrangements, and other transactions that reference LIBOR. ASU 2020-04 was effective upon issuance for all entities and through December 31, 2022. In December 2022, the FASB issued ASU 2022-06 - *Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848* which is effective on issuance and defers the sunset date of Topic 848 from December 31, 2022, to December 31, 2024, after which entities will no longer be permitted to apply the relief in Topic 848. The adoption of ASU 2022-06 did not have a material impact on the Company's operating results, financial position or disclosures.

Future Accounting Standard Changes

ASU 2021-08 - *Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers*, was issued in October 2021. The update, which can be adopted retrospectively or prospectively, requires the application of Topic 606 to recognize and measure contract assets and contract liabilities in a business combination. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2022. The Company expects to adopt this ASU prospectively for future business combinations, with no impact at the time of adoption.

The Company considers the applicability and the impact of all ASUs. ASUs not discussed above were assessed and determined to be either not applicable, the effects of adoption are not expected to be material or are clarifications of ASUs previously disclosed.

3. ACCOUNTS RECEIVABLE, NET

The accounts receivable, net balances consist of:

December 31,		**2022**		2021
Trade receivables from sales of crude oil and natural gas	**$**	**24,097,294**	$	18,110,135
Joint interest billing receivables and other		**2,368,914**		687,500
Accounts receivable, net	**$**	**26,466,208**	$	18,797,635

The Company has not had significant credit losses in the past and believes its accounts receivables are fully collectible. As such, no allowance for expected losses has been made as of December 31, 2022 and 2021, and no bad debt expense was recognized in the years presented in these financial statements.

4. OIL AND NATURAL GAS PROPERTIES

The property, plant and equipment, net balances consist of:

December 31,	2022	2021
Oil and natural gas properties:		
Evaluated (subject to depletion)	**$ 347,541,801**	$ 110,155,103
Unproved and unevaluated (not subject to depletion)	**42,866,767**	24,987,312
Total oil and gas properties	**390,408,568**	135,142,415
Accumulated depreciation, depletion, and amortization	**(87,993,495)**	(25,911,025)
Oil and gas properties, net	**$ 302,415,073**	$ 109,231,390

The Company recognized depletion and depreciation of $62,082,471 during the year ended December 31, 2022 (December 31, 2021 - $23,497,715). The depletion per barrel of oil equivalent ("BOE") produced was an average of $16.18 for the year ended December 31, 2022 (December 31, 2021 - $15.66).

The unproved and unevaluated property costs not subject to depletion as of December 31, 2022 and the year in which these costs were incurred, are as follows:

Description	2022	2021	2020	2019 and prior	Total
Costs incurred for:					
Property acquisition	$ 2,244,517	$4,300,745	$ -	$1,243,615	$ 7,788,877
Exploration	1,635,842	1,222,509	-	-	2,858,351
Development	32,219,539	-	-	-	32,219,539
Total unproved and unevaluated (not subject to depletion)	$36,099,898	$5,523,254	$ -	$1,243,615	$42,866,767

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, but may also include broker and legal expenses, geological and geophysical expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties.

Property acquisition costs incurred that remain in unproved and unevaluated property as at December 31, 2022 are mainly related to the Company's in progress development of wells in both the Giddings and the Hawkville fields. The Company believes that the majority of these unproved costs will become subject to depletion within the next two to three years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur.

Costs excluded from depletion also include those costs associated with exploration and development wells in progress or awaiting completion at year-end. These costs are transferred into the depletion base on an ongoing basis as these wells are completed and proved reserves are established or confirmed. The Company anticipates that the majority of the costs associated with these wells in progress at December 31, 2022 will be transferred to the amortization base during 2023. Unproved and unevaluated property costs for exploration and development wells incurred in years prior to 2022 are costs related to the advanced preparation for wells that the Company intends to drill in the future.

5. LEASES

The Company's leases consist of leases for office space, which are classified as operating leases.

The Company incurred total operating lease costs of $137,782 during the year ended December 31, 2022 (December 31, 2021 - $74,101), and total variable lease costs of $77,705 during the year ended December 31, 2022 (December 31, 2021 - $1,069). These costs are included within general and administrative expenses on the consolidated statements of operations and comprehensive income (loss).

The cash paid for amounts included in the measurement of lease liabilities were $144,539 during the year ended December 31, 2022 (December 31, 2021 - $nil). This amount is included in operating activities in the consolidated statements of cash flows.

As at December 31, 2022, the operating lease liabilities are expected to mature as follows:

		Operating Leases
2023	$	234,092
2024		237,524
2025		181,363
Total undiscounted lease payments		652,979
Less: effect of discounting		(41,088)
Total lease liability	$	**611,891**

The Company has also entered into an agreement for the lease of new office space, which has not commenced as at December 31, 2022, and has thereby not yet been recognized. The lease is expected to commence in the fall of 2023. The initial non-cancellable term of this lease is for 10 years, with the undiscounted lease payments over the non-cancellable term equal to $2,226,432, plus variable lease costs for operating costs.

6. ASSET RETIREMENT OBLIGATIONS

		2022		2021
Balance as at January 1	**$**	**431,704**	$	219,937
Liabilities incurred and acquired		**89,636**		121,553
Liabilities settled		**(127,862)**		(29,913)
Revision of estimates		**20,844**		95,918
Accretion expense		**43,756**		24,209
Balance as at December 31	**$**	**458,078**	$	431,704

The total future AROs were estimated based on the Company's net ownership interest in petroleum and natural gas assets including well sites, the estimated costs to abandon and reclaim the petroleum and natural gas assets and the estimated timing of the costs to be incurred in future periods.

As at December 31, 2022, the Company estimated the total undiscounted amount of cash flows required to settle its ARO to be approximately $2,634,225 (December 31, 2021 – $ 1,340,178) which will be incurred between 2023 and 2054. As at December 31, 2022, a weighted average credit-adjusted risk-free interest rate of 10.32% (December 31, 2021 – 9.73%) and an inflation rate of 2.28% (December 31, 2021 – 2.42%) were used to calculate the ARO.

The Company has no assets that are legally restricted for purposes of settling AROs.

7. DEBT

Asset Backed Securitization Facility

In 2022, the Company entered into an asset backed securitization of certain producing oil and gas wells (the "ABS Facility"). The ABS Facility is led by an insurance company, and all borrowings under the ABS Facility are secured by working interests in a subset of the Company's producing assets, which are held by a subsidiary of its operating subsidiary, Origination.

The ABS Facility consists of the following tranches:

- On April 27, 2022 the ABS Facility had an initial size of $80,000,000 ("Tranche 1") with additional capacity to expand up to $150,000,000 in total based on the underlying collateral. Tranche 1 of the ABS Facility carries an interest rate of LIBOR+6% (with a 1% LIBOR floor) for the initial year, LIBOR +12% (with a 1% LIBOR floor) for the second year. Tranche 1 has an initial maturity date of one year, with the Company having the option to extend an additional year to an ultimate maturity date of April 2024. Interest payments are required monthly.

- On September 12, 2022 the ABS Facility was increased by $55,000,000 ("Tranche 2"), to a total size of $135,000,000. Tranche 2 of the ABS Facility carries an interest rate of LIBOR+8% (with a 1% LIBOR floor) for the initial year, LIBOR +14% (with a 1% LIBOR floor) for the second year. Tranche 2 has an initial maturity date of one year, with the Company having the option to extend an additional year to an ultimate maturity date of September 2024. Interest payments are required monthly.

The Company's subsidiaries have certain financial covenants under the ABS Facility, including maintaining a debt service coverage ratio of no less that 1.1 to 1.0.

Under the terms of the ABS Facility, the Company is also required to:

(i) As of the initial borrowing date, enter into certain forward commodity swap contracts included in Note 18 which it has done.

(ii) Maintain an interest reserve account that will hold a cash balance sufficient to cover three months of scheduled interest payments (Note 2 - restricted cash).

Repayments of the undiscounted principal required under the ABS Facility for each year noted are as follows:

2023	$	61,630,567
2024		48,352,110
2025 and thereafter		-
Total	$	109,982,677

In addition to the required principal repayments outlined above, the Company's subsidiaries could also be required to make additional payments:

(i) if the debt service coverage ratio is less than 1.20 to 1.00, the Company must make an additional principal prepayment equal to net income/(loss) adjusted for all non-cash charges, plus/(minus) working capital not including the current portion of debt under this facility and other adjustments required under the terms of the agreement.

(ii) if the production tracking ratio is less than 80%, the Company must make an additional principal prepayment equal to net income/(loss) adjusted for all non-cash charges, plus/(minus) working capital not including the current portion of debt under this facility and other adjustments required under the terms of the agreement.

(iii) if the loan to value is above 85%, the Company must make an additional principal prepayment equal to net income/(loss) adjusted for all non-cash charges, plus/(minus) working capital not including the current portion of debt under this facility and other adjustments required under the terms of the agreement.

At December 31, 2022, the Company was not subject to any other additional principal prepayments.

The carrying value of the outstanding loan balances is composed of:

December 31, 2022		Current		Long-term		**Total (net)**
Principal drawn	$	61,630,567	$	48,352,110	**$**	**109,982,677**
Unamortized discount and interest at the imputed rate		680,615		842,926		**1,523,541**
Unamortized debt issuance costs		(2,084,263)		(516,328)		**(2,600,591)**
Total (net)	$	60,226,919	$	48,678,708	**$**	**108,905,627**

As the ABS Facility is an increasing rate debt, finance expense is recognized based on the imputed effective interest rate of 12.2% and 13.6% for Tranche 1 and 2 over the expected two-year term of each tranche, respectively, plus the LIBOR interest rate component. As a result, interest expense recognized in the first year of each tranche will exceed interest paid, and effectively result in an interest accrual, shown as unamortized discount and interest at the imputed rate above. For the year ended December 31, 2022, the Company incurred $8,968,929 of finance expense (December 31, 2021 - $nil), and interest paid on the ABS Facility was $5,808,996.

Goldman Facility

On December 22, 2020, the Company entered into a credit facility with Goldman Sachs (the "Goldman Facility"). All borrowings under the Goldman Facility were secured by the Company's oil and gas producing wells and the assets of three of the Company's subsidiaries. The Goldman Facility carried an interest rate of LIBOR+6% (with a 1% LIBOR floor) and had a maturity date of December 2031. Interest payments were required quarterly.

In April 2022, in connection with the ABS Facility, the Company repaid the Goldman Facility in full and amortized the remaining unamortized borrowing costs.

The outstanding balances under this facility were as follows:

December 31, 2022		Current		Long-term		**Total (net)**
Principal drawn		-		-		-
Unamortized discount and debt issuance costs		-		-		-
Total (net)		-		-		-

December 31, 2021		Current		Long-term		**Total (net)**
Principal drawn	$	7,722,206	$	17,515,203	$	25,237,409
Unamortized discount and debt issuance costs		(662,372)		(1,375,896)		(2,038,268)
Total (net)	$	7,059,834	$	16,139,307	$	23,199,141

For the year ended December 31, 2022, the Company incurred $2,420,486 of finance expense related to the facility (December 31, 2021 - $3,612,927).

Corporate Credit Facility

In October 2021, the Company's operating subsidiary Origination closed on a corporate credit facility (the "Corporate Credit Facility"). The Corporate Credit Facility had a maximum borrowing capacity of $12,500,000, subject to quarterly borrowing base determinations by the lender. The loan charged interest at prime +2.25% and had a one-year maturity. A subset of certain Company working interests in producing assets were secured in connection with the Corporate Credit Facility.

During the first quarter of 2022, Origination closed a new Corporate Credit Facility to replace the previous facility. The new Corporate Credit Facility had a maximum borrowing capacity of $30,000,000, which was subsequently increased in October 2022 to $65,000,000, subject to quarterly borrowing base determinations by the lender. The Corporate Credit Facility is secured by working interests in a subset of the Company's producing assets and charges interest at the greater of 5.00% and prime +1.75% and has a one-year maturity.

As of December 31, 2022, the Company had drawn $41,500,000 under the Corporate Credit Facility (December 31, 2021 - $2,200,000), and for the year ended December 31, 2022, incurred $1,736,868 of interest expense related to the facility (December 31, 2021 - $nil). The borrowing base as of December 31, 2022 was $64,435,764 (December 31, 2021- $6,579,750).

8. OTHER DEBT INSTRUMENTS

Asset Backed Preferred Instruments

On March 5, 2021, Origination executed an Origination Member Units buy-back structure, in which a member exchanged 100% of their holdings (3,992,629 Origination Member Units representing approximately 23.4% of the outstanding Origination Member Units at the time) along with a $1,000,000 promissory note for 23,500,000 mandatorily redeemable units in a newly created limited partnership controlled by Origination (the "LP Units"). The redemption terms of these LP Units required:

- 6,670,000 of the LP Units were required to be redeemed at the following prices per unit, depending on when the redemption was made: before May 1, 2021 at $0.71 per LP Unit, or thereafter but before June 1, 2021 at $0.8809 per LP Unit, or thereafter but before September 1, 2021 at $1.00 per LP Unit. If not paid by September 1, 2021, the LP Units would be considered in default.

- The remaining 16,830,000 LP Units were required to be redeemed at $1.00 per LP Unit by March 5, 2024. If not redeemed by that date, the redemption price would increase to $1.35 per LP Unit and the Company would be considered to be in default.

While outstanding, all LP Units earned a fixed rate of return of 12% per annum, which increased to 17% in any event of default.

The LP Units were determined to be mandatorily redeemable instruments, classified as a liability, initially measured at fair value and subsequently at amortized cost.

As a result of the buy-back, the Company recorded a reduction to Origination Member Units of $8,680,786 (weighted average issue price of $21.7/unit) a reduction in promissory note liability of $1,000,000, a liability for the LP Units at an initial fair value of $21,565,702 and a reduction to accumulated deficit of $11,884,916. The fair value of the LP Units was determined by discounting the expected cash flows related to the instrument at the market-based rate of 12% per annum at that time.

In the second quarter of 2021, the Company redeemed 6,670,000 LP Units at $0.71 per LP Unit for a total amount of $4,735,700. In 2022, the Company redeemed the remaining LP Units for $16,830,000, plus accrued interest of $2,515,398, using the proceeds from the ABS Facility (Note 7).

For the year ended December 31, 2022, the Company recorded finance expense related to the outstanding LP Units in the amount $658,047 (December 31, 2021 - $1,857,351).

Promissory and Convertible Promissory Notes

The Company did not have promissory and convertible promissory notes outstanding during the year ended December 31, 2022.

	2022	2021
Balance as at January 1	-	$ 5,425,000
Issued for cash	-	3,375,000
Converted to Origination Member Units	-	(3,475,000)
Converted to LP Units	-	(1,000,000)
Repayment of notes	-	(2,025,000)
Converted to Origination Member Units	-	(2,300,000)
Balance as at December 31	-	-

During the year ended December 31, 2021, Origination issued $3,375,000 in promissory and convertible promissory notes for cash, some of which were held by officers of the Company.

The outstanding promissory notes were settled as follows in the year ended December 31, 2021:

- $3,475,000 in promissory notes were settled via the issuance of 353,870 Origination Member Units, and $1,000,000 in promissory notes was exchanged and settled as part of the receipt of LP Units, in connection with the Asset Backed Preferred Instrument.

- $1,755,000 in promissory notes was paid in cash, and $270,000 in promissory notes was offset with agreed upon overhead expenses paid by the Company on behalf of the note holders, which was shown as a reduction of general and administrative expenses.

- $2,300,000 of the convertible promissory notes were converted into 234,216 Origination Member Units.

For the year ended December 31, 2022, the Company recorded finance expense related to the promissory and convertible promissory notes in the amount of $nil (December 31, 2021 - $300,685).

9. REDEEMABLE NON-CONTROLLING INTERESTS

The following table outlines the movement in redeemable non-controlling interests in the years presented.

		2022		2021
Balance as at January 1	$	**46,552,839**	$	-
Redeemable non-controlling interests issued		**154,456,707**		55,138,395
Net loss and comprehensive loss attributed		**10,598,514**		12,851,005
Revaluation to redemption value, net		**23,197,507**		240,903
Distributions		**(3,340,254)**		(6,388,870)
Settlement		**(123,881,576)**		(15,288,594)
Balance as at December 31	**$**	**107,583,737**	$	46,552,839

The Company has established the Development Partnerships as a mechanism to partially finance its development projects and activities. The redeemable non-controlling interest reflects the development partnership units that are not held by the Company either directly or indirectly. These external units consist of: (a) the Flat Payout Units, and (b) the IRR Payout Units.

The Flat Payout Units and the IRR Payout Units are entitled to 75% of the distributions of the related development partnership, until the "Base Payout" amount is received. The Base Payout is:

(a) For the Flat Payout Units - an amount equal to the invested capital.

(b) For the IRR Payout Units - an amount equal to the greater of (i) the invested capital plus a 15% annualized return and (ii) 120% of the initial investment.

After the Base Payout has been achieved, the participation in subsequent distribution will reduce to 20% of the Flat Payout Units held and 6% of the IRR Payout Units held. At that time, the unit holders also have the right to redeem (the "Put Right") the units for either (i) Class B non-voting units of Origination (which are exchangeable on a one-for-one basis for SVS shares of the Company), or (ii) cash, subject to certain restrictions, and with the number of shares or cash to be distributed to be calculated based on future net present values of the oil and gas reserves of the related development partnership.

Development Partnership 1 ("DP1")

During the first quarter of 2021, the Company formed DP1 with 13 external limited partners and Origination as a limited partner and the general partner. The intention of the DP1 was to partially finance the drilling and completion of five wells, with the external partners funding approximately 60% and the Company funding 40%. The Company raised $13,140,240 from external limited partners of which $1,366,709 was raised from officers and directors of the Company at that time. Investors participated $3,252,132 in Flat Payout Units and $9,888,108 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $nil to external partners (2021 - $1,853,127).

On October 7, 2021, on completion of the DP1 program, the Company liquidated DP1 and redeemed the associated redeemable non-controlling interests with a redemption value of $15,288,594. As part of this redemption, DP1 units with a redemption value of $1,192,893 were exchanged for 339,372 Class B non-voting units of Origination via the Put Right.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in DP1 was $nil (December 31, 2021 - $15,288,594).

Development Partnership 2 ("DP2")

During the third quarter of 2021, the Company formed DP2 with 25 external limited partners and Origination as a limited partner and the general partner. The intention of the DP2 was to partially finance the drilling and completion of five wells, with the external partners funding approximately 60% and the Company funding 40%. The Company raised $20,815,329 from external limited partners of which $1,724,967 was raised from officers and directors of the Company at that time. Investors participated $7,390,362 in Flat Payout Units and $13,424,967 in IRR Payout Units.

During the year ended December 31, 2021, the Company distributed $4,535,743 to external partners.

In January 2022, on completion of the DP2 program, the Company liquidated DP2 and redeemed the associated redeemable non-controlling interests with a redemption value of $23,511,818. As part of this redemption, DP2 units with a redemption value of (a) $3,159,695 were exchanged for 826,063 Class B non-voting units of Origination via the Put Right, and (b) $84,300 retained the ongoing rights of working interest in the DP2 wells and as a result, the fair value of the units was settled with a disposition from PP&E, reflecting the disposition of the associated working interest.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in DP2 was $nil (December 31, 2021 - redemption value of $23,511,818 and carrying value of $25,370,013, respectively).

Development Partnership 3 ("DP3")

During the fourth quarter of 2021, the Company formed DP3 with 23 external limited partners and Origination as a limited partner and the general partner. The intention of the DP3 was to partially finance the drilling and completion of five wells, with the external partners funding approximately 60% and the Company funding 40%. The Company raised $21,182,826 from external limited partners of which $4,032,672 was raised from officers and directors of the Company. Investors participated $10,413,322 in Flat Payout Units and $10,769,504 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $nil to external partners (2021 - $nil).

In April 2022, on completion of the DP3 program, the Company liquidated DP3 and redeemed the associated redeemable non-controlling interests with a redemption value of $30,171,337. As part of this redemption, DP3 units with a redemption value of $5,102,229 were exchanged for 894,929 Class B non-voting units of Origination via the Put Right.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in DP3 was $nil (December 31, 2021 - $21,182,826).

Development Partnership 4 ("DP4")

During the first quarter of 2022, the Company formed DP4 with 29 external limited partners and Origination as a limited partner and the general partner. The intention of DP4 was to partially finance the drilling and completion of five wells, with the external partners funding approximately 60% and the Company funding 40%. The Company has raised $25,225,079 from external limited partners of which $1,484,256 was raised from officers and directors of the Company. Investors participated $11,638,948 in Flat Payout Units and $13,586,130 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $2,747,270 to external partners.

In July 2022, on completion of the DP4 program, the Company liquidated DP4 and redeemed the associated redeemable non-controlling interests with a redemption value of $31,734,290. As part of this redemption, DP4 units with a redemption value of (a) $4,135,797 were exchanged for 706,975 Class B non-voting units of Origination via the Put Right, and (b) $291,599 retained the ongoing rights of working interest in the DP4 wells and as a result, the fair value of the units was settled with a disposition from PP&E, reflecting the disposition of the associated working interest.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in DP4 was $nil (December 31, 2021 - $nil).

Development Partnership Red Dawn 1 ("Red Dawn 1")

During the first quarter of 2022, the Company formed Red Dawn 1 with 37 external limited partners and Origination as a limited partner and the general partner. The intention of Red Dawn 1 is to partially finance the drilling and completion of five wells, with the external partners funding approximately 60% and the Company funding 40%. The Company has raised $30,269,097 from external limited partners of which $773,836 was raised from officers and directors of the Company. Investors participated $16,692,200 in Flat Payout Units and $13,576,895 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $nil to external partners.

In November 2022, on completion of the Red Dawn 1 program, the Company liquidated Red Dawn 1 and redeemed the associated redeemable non-controlling interests with a redemption value of $38,464,144. As part of this redemption, Red Dawn 1 units with a redemption value of (a) $3,184,247 were exchanged for 617,103 Class B non-voting units of Origination via the Put Right, and (b)

$166,684 retained the ongoing rights of working interest in the Red Dawn 1 wells and as a result, the fair value of the units was settled with a disposition from PP&E, reflecting the disposition of the associated working interest.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in Red Dawn 1 was $nil (December 31, 2021 - $nil).

Development Partnership 5 ("DP5")

During the second quarter of 2022, the Company formed DP5 with 25 external limited partners and Origination as a limited partner and the general partner. The intention of DP5 is to partially finance the drilling and completion of six wells, with the external partners funding approximately 60% and the Company funding 40%. The Company has raised $30,171,345 from external limited partners of which $4,308,462 was raised from officers and directors of the Company. Investors participated $19,657,921 in Flat Payout Units and $10,513,413 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $450,668 to external partners.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in DP5 was $36,354,869 (December 31, 2021 - $nil).

Development Partnership 6 ("DP6")

During the third quarter of 2022, the Company formed DP6 with 38 external limited partners and Origination as a limited partner and the general partner. The intention of DP6 is to partially finance the drilling and completion of ten wells, with the external partners funding approximately 60% and the Company funding 40%. The Company has raised $34,157,892 from external limited partners of which $2,215,096 was raised from officers and directors of the Company. Investors participated $21,176,246 in Flat Payout Units and $12,981,645 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $142,316 to external partners.

As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in DP6 was $36,595,572 (December 31, 2021 - $nil).

Development Partnership Red Dawn II ("Red Dawn 2")

During the fourth quarter of 2022, the Company formed Red Dawn 2 with 36 external limited partners and Origination as a limited partner and the general partner. The intention of Red Dawn 2 is to partially finance the drilling and completion of five wells, with the external partners funding approximately 60% and the Company funding 40%. The Company has raised $34,633,295 from external limited partners of which $872,944 was raised from officers and directors of the Company. Investors participated $20,645,955 in Flat Payout Units and $13,987,340 in IRR Payout Units.

During the year ended December 31, 2022, the Company distributed $nil to external partners.

The Red Dawn 2 program has not been completed as at December 31, 2022. As at December 31, 2022 both the redemption value and carrying value of the Redeemable NCI in Red Dawn 2 was $34,633,295 (December 31, 2021 - $nil).

10. NON-CONTROLLING INTERESTS

The NCI reflects the Class B non-voting units of Origination that are not held by the Company either directly or indirectly. There are 19,552,864 outstanding Class B non-voting units of Origination held by external holders, reflecting a 35.967% economic interest in Origination as of December 31, 2022 (December 31, 2021 - 32.954%).

2022 Activities

In 2022, the following development partnership units were exchanged for Class B non-voting units of Origination (Note 9), as follows:

a. DP2: 826,063 Class B non-voting units of Origination were issued, with a value of $3,159,695.

b. DP3: 894,929 Class B non-voting units of Origination were issued, with a value of $5,102,229.

c. DP4: 706,975 Class B non-voting units of Origination were issued, with a value of $4,135,797.

d. Red Dawn 1: 617,103 Class B non-voting units of Origination were issued, with a value of $3,184,247.

The issuance of these Class B units is reflected as a reduction to Redeemable NCI for the value at which these units were issued, an increase to NCI for the change in the Company's share in Origination's net assets, and an increase to additional paid-in capital for the difference.

During the year ended December 31, 2022, Origination:

a. Repurchased and cancelled 799,600 of its Class A units, held by the Company, to match the number of SVS cancelled by the Company (Note 11).

b. Issued 2,024,401 of its Class A units to the Company, to match the number of SVS issued by the Company in connection with the settlement of certain RSUs (Note 12).

The change in these Class A units resulted in a change to the NCI ownership, triggering an adjustment to the carrying value of NCI, with a corresponding offset to additional paid-in capital.

Origination declared and paid dividends to its Class B non-voting units of Origination totaling $6,552,683, for the year ended December 31, 2022, resulting in a decrease of non-controlling interest.

2021 Activities

On closing the BCA, Origination's consolidated book value of net liabilities was $35,344,612, which results in an opening NCI balance of $11,486,999. This NCI balance along with the weighted average stated capital of the equity interests surrendered by the NCI holder of $18,721,276, for a total of $30,208,275, has been credited to additional paid in-capital.

In October 2021, development partnership units of DP1 were exchanged for 339,372 Class B non-voting units of Origination at a value of $1,192,893 (Note 9), reflecting a reduction to Redeemable NCI for the value at which these units were issued, an increase to NCI for the change in the Company's share in Origination's net assets, and an increase to additional paid-in capital for the difference

11. EQUITY

Authorized Share capital

The Company is authorized to issue an unlimited number of SVS, MVS, and PVS, with no par value. Subject to certain restrictions set out in the Company's articles, each SVS is entitled to one vote per share, each MVS is convertible, at the option of the holder, into 100 SVS and entitles the holder to 100 votes per share and each PVS is convertible into one SVS and entitles the holder to 1,000 votes per share. Each PVS will automatically convert to one SVS upon the holder's equity interest in Origination reducing to less than 75% of the interest held on the date of the closing of the BCA.

The following table summarizes the movements in the Company's common shares:

	Origination Member Units		SVS Shares		MVS Shares		PVS Shares		**Total Share Capital**
	Shares	Amount	Shares	Amount	Shares	Amount	Shares	Amount	
Balance as at January 1, 2021	17,083,501	$ 37,097,376	-	$ -	-	$ -	-	$ -	**$ 37,097,376**
Issuance of member units for cash	819,215	8,044,700	-	-	-	-	-	-	**8,044,700**
Issuance of member units exchanged for notes	353,870	3,475,000	-	-	-	-	-	-	**3,475,000**
Issuance of member units for oil and gas properties	356,415	3,499,995	-	-	-	-	-	-	**3,499,995**
Issuance of member units to contractors	923,954	9,073,228	-	-	-	-	-	-	**9,073,228**
Redemption of member units	(3,992,629)	(8,680,786)	-	-	-	-	-	-	**(8,680,786)**
Issuance of member units exchanged for notes	234,216	2,300,000	-	-	-	-	-	-	**2,300,000**
Origination Member Units split 1:3	31,557,084	-	-	-	-	-	-	-	**-**
Allocation of opening non-controlling interest	(16,168,422)	(18,721,276)	-	-	-	-	-	-	**(18,721,276)**
Exchange of units for SVS and MVS	(31,167,204)	(36,088,237)	1,427,421	1,652,798	297,398	34,435,439	-	-	**-**
Shares issued for cash, net of share issuance costs of $247,218	-	-	161,976	476,978	17,057	5,022,854	-	-	**5,499,832**
PVS issued for cash	-	-	-	-	-	-	15,947	128,213	**128,213**
Shares issued on reverse recapitalization	-	-	534,384	1,697,865	-	-	-	-	**1,697,865**
Conversion of MVS to SVS	-	-	30,411,950	38,161,379	(304,120)	(38,161,379)	-	-	**-**
Balance as at December 31, 2021	**-**	**$ -**	**32,535,731**	**$ 41,989,020**	**10,335**	**$ 1,296,914**	**15,947**	**$ 128,213**	**$ 43,414,147**
Exchange of units for SVS and MVS	-	-	195,541	245,368	(1,955)	(245,368)	-	-	**-**
Settlement of RSUs	-	-	2,024,401	9,685,555	-	-	-	-	**9,685,555**
Repurchase of SVS for cancellation	-	-	(799,600)	(4,324,915)	-	-	-	-	**(4,324,915)**
Balance as at December 31, 2022	**-**	**$ -**	**33,956,073**	**$ 47,595,028**	**8,380**	**$ 1,051,546**	**15,947**	**$ 128,213**	**$ 48,774,787**

2022 Activity

On June 10, 2022, the TSX Venture Exchange ("TSXV") approved the Company's normal course issuer bid ("NCIB"). Under the NCIB, the Company may purchase, for cancellation, up to 1,648,783 SVS of the Company (representing approximately 5% of its issued and outstanding SVS as of June 6, 2022) over a 12-month period commencing on June 10, 2022. The NCIB will expire no later than June 9, 2023.

On September 27, 2022, the TSXV approved an amendment to the Company's NCIB, which permits the Company to enter into an automatic share purchase plan ("ASPP") to facilitate the purchase of SVS under the NCIB during times when the Company would not ordinarily be permitted to purchase such shares due to regulatory restrictions of self-imposed black-out periods.

In connection with the NCIB, during 2022 the Company purchased and cancelled 799,600 SVS at an average price of $5.41/share for an aggregate value of $4,324,915, and as at December 31, 2022, recorded a liability of $4,670,507, representing the contractual maximum share purchases remaining under the ASPP at an amended maximum purchase price of $5.50 per share.

During 2022, 1,955 MVS were converted into 195,541 SVS on a 100 to 1 basis, and 2,024,401 SVS were issued as a result of settling certain RSUs (Note 12).

Previously recorded stock-based compensation of $9,685,555 has been removed from additional paid-in capital and has been reclassified to share capital to reflect the impact of settlement (Note 12).

2021 Activity

During the year ended December 31, 2021, the Company issued 819,215 Origination Member Units for aggregate cash of $8,044,700 ($9.82/unit) and issued 353,870 Origination Member Units in exchange for the retirement of $3,475,000 in promissory notes ($9.82/unit).

The Company entered into an agreement, with a third party, to acquire 16,201 net acres in the Eagle Ford formation, located in the Austin, Fayette, Lee and Washington counties of Texas. In exchange for the acreage, the Company issued 203,666 Origination Member Units valued at $2,000,000 ($9.82/unit).

In addition, the Company issued 152,749 Origination Member Units, valued at $1,499,995 ($9.82/unit) in exchange for an approximately 630 net mineral acreage in Washington County, Texas.

In May of 2021, the Company issued 923,954 Origination Member Units to officers and consultants of the Company for services at an estimated value of $9.82 per Origination Member Unit for total consideration of $9,073,228 in connection with the listing application.

On July 2, 2021, the Company exercised its option to convert all the existing convertible promissory notes with a principal of $2,300,000 into 234,216 Origination Member Units ($9.82/unit) effective as of July 7, 2021.

During the year ended December 31, 2021, 304,120 MVS shares were converted into 30,411,950 SVS.

Dividends

The Company implemented a dividend distribution policy, starting January 2022, where monthly dividends of $0.03 per SVS and PVS and $3.00 per MVS were declared each month, with aggregate dividends declared and paid in 2022 of $12,416,759 (2021 - $nil). There are no restrictions that limit the payment of dividends by the Company.

The total dividends declared and paid during the year ended December 31, 2022 by class of shares was $12,092,734, $318,284, and $5,741 for shares of SVS, MVS, and PVS, respectively (2021 - $nil).

12. SHARE BASED COMPENSATION

The Company has granted share-based compensation consisting of share purchase options and restricted share units ("RSUs") under the terms of the 2021 Stock and Incentive Plan, which was approved by shareholders in May 2021 and adopted by the Board in September 2021. The options and RSUs have been granted with time-based vesting provisions over a period of 0 to 3 years. Vested RSUs will settle in Subordinate Voting Shares on a one-to-one basis as soon as practicable following the vesting date, and vested options will settle in Subordinate Voting Shares on a one-to-one basis as soon as practicable following the exercise date.

Additionally, the Company awarded deferred share units ("DSUs") to directors as compensation for service under the terms of the Deferred Share Unit Plan, which was approved by shareholders in May 2021 and adopted by the Board in September 2021. The initial tranche of DSUs vested on June 1, 2022, and subsequent awards vest twelve months following the date of grant. Vested DSUs will settle in Subordinate Voting Shares on a one-to-one basis as soon as practicable following the termination of service of an eligible director.

Compensation expense for share-based awards was $10,197,720 during year ended December 31, 2022 (December 31, 2021 - $5,405,548). These amounts are included in general and administrative expense in the consolidated statements of operations and comprehensive income (loss). The activity and assumptions for the share-based compensation plans are included below.

Share Purchase Options

The options outstanding under this plan are as follows:

	Stock options outstanding		Weighted-average exercise price	Weighted average remaining contractual term (years)		Aggregate Intrinsic Value
Outstanding, January 1, 2022	2,834,288	$	**3.56**			
Granted	-		-			
Forfeited	-		-			
Expired	-		-			
Exercised[1]	-		-			
Outstanding, December 31, 2022	**2,834,288**	$	**3.56**	**8.95**	$	**4,166,403**
Exercisable, December 31, 2022	**1,803,985**	$	**3.56**	**8.95**	$	**2,651,858**

[1]No options were exercised during the years ended December 31, 2022 or 2021

The weighted average assumptions used to determine the fair value of the options granted, using the Black-Scholes options pricing model are as follows:

For the year ended, December 31,	**2022**	**2021**
Fair value of options granted	N/A	2.21
Valuation assumptions:		
Expected life (years)	5.55	5.72
Risk-free interest rate	1.27%	1.27%
Average forfeiture rate	0.00%	0.00%
Expected dividend yield	0.00%	0.00%
Expected volatility	71.62%	71.62%

The Company incurred share-based compensation expense related to the stock options of $2,046,166 during the year ended December 31, 2022 (December 31, 2021 - $2,858,702). As of December 31, 2022, the Company had $1,293,484 of unrecognized compensation expense related to non-vested stock options. The remaining expense is expected to be recognized over a weighted average period of approximately 1.4 years.

Restricted Share Units

As of December 31, 2022, the Company's nonvested RSUs outstanding are as follows:

	Restricted Share Units		Weighted-average grant date fair value	Weighted average remaining contractual term (years)		Aggregate Intrinsic Value
Nonvested, January 1, 2022	892,580	$	3.56			
Granted[1]	1,214,321		5.75			
Forfeited	-		-			
Vested and settled[2]	(2,024,401)		4.78			
Nonvested, December 31, 2022	**82,500**	$	**5.75**	**0.67**	$	**414,975**

[1]The weighted-average grant-date fair value of the RSUs granted in 2021 was $3.56 per unit.

[2]The settlement date fair value of the RSUs that vested and settled during the years ended December 31, 2022 and 2021 was $11,609,135 and $nil, respectively.

The Company incurred share-based compensation expense related to the RSUs of $7,415,252 during the year ended December 31, 2022 (December 31, 2021 - $2,488,955). As of December 31, 2022, the Company had $252,724 of unrecognized compensation expense related to non-vested RSUs. The expense is expected to be recognized over a weighted average period of approximately 0.67 years.

Deferred Share Units

As of December 31, 2022, the Company's DSUs outstanding are as follows:

	Deferred Share Units		Weighted-average grant date fair value	Weighted average remaining contractual term (years)		Aggregate Intrinsic Value
Outstanding, January 1, 2022	137,641	$	3.56			
Granted[1]	88,694		5.75			
Forfeited	-		-			
Settled	-		-			
Outstanding, December 31, 2022	**226,335**	**$**	**4.42**	**0.42**	$	**1,138,465**
Vested[2], December 31, 2022	**137,641**	**$**	**3.56**	**N/A**	$	**692,334**

[1]The weighted-average grant-date fair value of the DSUs granted in 2021 was $3.56 per unit.

[2]The fair value of the DSUs that vested during the years ended December 31, 2022 and 2021 was $490,002 and $nil, respectively.

The Company incurred share-based compensation expense related to the DSUs of $736,302 during the year ended December 31, 2022 (December 31, 2021 - $51,891). As of December 31, 2022, the Company had $211,800 of unrecognized compensation expense related to non-vested DSUs. The expense is expected to be recognized within one year of grant.

13. EARNINGS PER SHARE

The Company's common shares consist of SVS, MVS, and PVS. Subject to certain restrictions set out in the Company's articles, the SVS, MVS, and PVS rank equally and are entitled to equal distributions, except for the MVS which receives 100 times the distribution entitlement.

As all three classes of common shares were determined to individually have the same entitlement to income (loss) per share on a basic and diluted basis, the below summarizes the amounts on an as-converted basis. The as-converted basis assumes the conversion of the PVS on a 1:1 basis into SVS, and the MVS on a 1:100 basis into SVS.

Basic EPS

The basic net income (loss) per share attributable to common shareholders for SVS, MVS, and PVS is determined using the two-class method.

The basic income (loss) per share on an as-converted basis to SVS is as follows:

For the year ended, December 31,		2022		2021
Net income (loss) attributable to common shareholders	**$**	**7,428,135**	$	(**32,344,428**)
Weighted average number of common shares outstanding (as-converted)		**34,453,696**		42,596,264
Income (loss) per share - basic	**$**	**0.22**	$	(0.76)

<u>*Diluted EPS*</u>

Diluted net income (loss) per share attributable to SVS shareholders is computed using the more dilutive of the if-converted or treasury stock method, whereas diluted net income (loss) per share attributable to MVS and PVS shareholders is computed using the two-class method.

The diluted income (loss) per share on an as-converted basis to SVS is as follows:

For the year ended, December 31,		2022		2021
Net income (loss) attributable to common shareholders	**$**	**7,428,135**	$	(32,344,428)
Plus: Effect of dilutive items		**3,189,196**		-
	$	**10,617,331**	$	(32,344,424)
Weighted average number of common shares outstanding (as-converted)		**34,453,696**		42,596,264
Plus: Effect for conversion of Origination Class B into SVS		**18,203,421**		-
Plus: Effect for dilutive share-based compensation awards		**929,210**		-
		53,586,327		42,596,264
Income (loss) per share - diluted	**$**	**0.20**	$	(0.76)

As for the year ended December 31, 2021 the Company reported a net loss, the potentially dilutive securities are antidilutive and accordingly, basic net loss per share equals diluted net loss per share for the year ended December 31, 2021.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

The amount of each significant category of revenue is as follows:

For the year ended, December 31,		2022		2021
Crude oil	**$**	**97,438,790**	$	50,868,794
Natural gas		**77,966,801**		10,286,929
Natural gas liquids		**20,243,366**		9,641,067
Total operating revenues	**$**	**195,648,957**	$	70,796,790

15. INCOME TAX

Prior to the RTO, Origination was not subject to U.S. income taxes because, as a limited liability company classified as a partnership for U.S. federal income tax purposes, it was treated as a pass-through entity for income tax purposes. As such the members of Origination were subject to income tax with respect to each such member's allocable share of Origination's taxable income. Subsequent to the RTO, while Origination remains classified as a partnership for U.S. federal income tax purposes, the Company is taxed as a United States corporation and is subject to U.S. federal (and applicable state) income tax on its allocable share of pass-through taxable income from Origination. Thus, any tax effects related to the Company, together with its share of Origination's activity, are included in these consolidated financial statements. Any taxable income or loss of Origination that is attributed to its other members is not taxable by the Company. The Company is also taxed as a Canadian corporation and is subject to Canada federal and provincial income tax for its share of Origination's taxable income combined with its own activity.

The Company's effective income tax rates (benefits) were (4.5%) and 5.9% for the years ended December 31, 2022, and 2021, respectively. The overall change in the Company's effective tax rate for the year ended December 31, 2022, from the previous year is primarily due to: (i) changes in amounts of income (loss) not subject to corporate tax and, (ii) current year activity causing the reversal of a previously recorded deferred tax expense resulting from temporary differences in items related to cost recovery of oil and natural gas properties.

For the years ended December 31, 2022, and 2021, the Company recorded income tax expense (benefit) of ($1,928,319) and $1,928,319, respectively. The Company's provision for income taxes is comprised of the following items for the period indicated.

Year ended December 31,		2022		2021
Current income tax expense:				
United States federal	**$**	**-**	**$**	**-**
State		**-**		**-**
Total current income tax expense		**-**		**-**
Deferred income tax expense (benefit):				
United States federal	**$**	**(1,928,319)**	$	1,928,319
State		**-**		**-**
Total deferred income tax expense (benefit)	**$**	**(1,928,319)**	$	1,928,319
Total income tax expense (benefit)	**$**	**(1,928,319)**	$	1,928,319

The difference in the Company's income tax provision calculated using its effective tax rates (benefits) of (4.5%) and 5.9% for the years ended December 31, 2022, and 2021, respectively, from the amounts calculated by applying the U.S. federal income tax rate of 21% to its pretax income (loss) from continuing operations were due to the following items for the periods indicated:

Year ended December 31,		2022		2021
Net income (loss) before taxes	**$**	**42,485,033**	$	(30,654,438)
U. S. federal statutory income tax rate		**21%**		21%
Expected federal taxes at statutory rate		**8,921,857**		(6,437,432)
Increase (decrease) resulting from:				
Canadian income tax		**-**		-
Non-controlling interests		**(7,766,896)**		54,250
Income (loss) not subject to corporate income taxes		**(1,154,961)**		6,383,182
Change in tax status		**-**		1,928,319
Change in valuation allowance - federal		**(1,928,319)**		-
Income tax expense (recovery)	**$**	**(1,928,319)**	$	1,928,319

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the Company's net deferred tax asset and liability were as follows for the periods indicated:

Year ended December 31,		**2022**		2021
Deferred tax liabilities				
Investment in Origination	**$**	**-**	$	(3,437,344)
Total deferred tax liabilities		-		(3,437,344)
Deferred tax assets				
Investment in Origination	$	**10,518,502**	$	1,509,025
Canadian federal tax loss carryforwards		**339,501**		334,198
US federal tax loss carryforwards		**9,361,332**		-
Total deferred tax assets, gross		**20,219,335**		1,843,223
Less: Valuation allowance		**(20,219,335)**		(334,198)
Total deferred tax assets, net		**-**		1,509,025
Net deferred tax assets (liabilities)		**-**		(1,928,319)
Presented as follows:				
Total deferred tax assets		-		-
Total deferred tax liabilities		-		(1,928,319)
Net deferred tax assets (liabilities)	**$**	**-**	$	(1,928,319)

The tax years ended December 31, 2019, through December 31, 2022, remain open to examination under the applicable statute of limitations in the United States and other jurisdictions in which the Company and its subsidiaries file income tax returns. In some instances, state statutes of limitations are longer than those under United States federal tax law. The Company believes that it is more likely than not that the benefit from the investment in Origination and its federal loss carryforward will not be realized. In recognitions of this risk, the Company has provided a valuation allowance as of December 31, 2022 and 2021 of $20,219,335 and $334,198, respectively.

The Canadian federal tax losses will expire after 20 years from the date incurred. The US federal tax loss carryforwards do not expire.

16. RELATED PARTY TRANSACTIONS

The Company's related parties consist of directors and officers of the Company, their immediate families, and companies that are controlled or significantly influenced by directors and officers of the Company.

Management Services Agreements & Other Related Party Balances

On December 22, 2020, the Company entered into a Management Services Agreement (the "MSA") with an entity related by virtue of common equity holders, directors and officers. Under this MSA, the related entity provided management, finance, operations and administrative services. The MSA had an initial period of 11 years with a 90 day cancellation notice. The Company was obligated to pay for these services on a quarterly basis amounting to the lesser of; i) $2.00 per produced barrel of oil equivalent (converting natural gas to BOE equivalent of 6:1), and ii) 0.375% of measured assets as defined in the credit agreement. During the year ended December 31, 2021, the Company incurred and paid fees of $287,126, recognized in in general and administrative expenses. In the second quarter of 2021, the MSA was effectively terminated, by assigning the MSA to one of the Company's subsidiaries. Therefore, no fees were incurred in connection with the MSA in the year ended December 31, 2022.

As part of terminating the MSA, the Company entered into a new Letter Agreement (the "Letter") in the second quarter of 2021, with the same related entity by virtue of common equity holders, directors and officers. The Letter requires the Company to hire its own employees, obtain its own office lease and assume certain management obligations. In exchange, the Company is paid an annual fee of $1,000,000 on a quarterly basis.

During the third quarter of 2022, the Letter was terminated by the Company.

During the year ended December 31, 2022, the Company received $916,667 (December 31, 2021 - $416,666 in connection with the Letter, which is included in general and administrative expenses in the consolidated statements of operations and comprehensive income (loss). As at December 31, 2022, amounts receivable of $nil (December 31, 2021 - $120,501) were included in accounts receivable, net on the consolidated balance sheets.

Other Related Party Balances

As at December 31, 2022, accounts payable and accrued liabilities included $143,572 (December 31, 2021 -$120,501) due from a company related by virtue of common equity holders, officers and directors under normal credit terms.

17. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants.

Hierarchy levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. The Company classifies fair values according to the following hierarchy based on the inputs used to value the instruments:

- Level 1: Reflects inputs that are based on unadjusted quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date.

- Level 2: Reflects inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly.

- Level 3: Reflects inputs that are both significant to the fair value measurement and less observable from objective sources.

Financial Assets and Liabilities

The Company's financial instruments are cash and cash equivalents, restricted cash, account receivable, net, derivative assets and liabilities, accounts payable and accrued liabilities, long term debt, corporate credit facility and the asset backed preferred instrument.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The Company classifies its financial assets and liabilities as follows within the hierarchy:

- **Derivatives:**

  Derivatives are financial instruments measured at fair value on a recurring basis.

  Commodity derivatives

  The fair value of the commodity derivative instruments is determined using observable market data for similar instruments, which resulted in the Company reporting its commodity derivatives as Level 2 on the fair value hierarchy. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs.

  Interest rate derivatives

  The fair value of the interest rate derivative instruments is determined using observable market data for forward curves for the benchmark interest rates, as well as time to maturity, contractual notional amounts, amongst other factors. The Company reports its interest rate derivatives as Level 2 on the fair value hierarchy. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs.

- **Cash, cash equivalents and restricted cash:** The fair value of cash, cash equivalents and restricted cash approximates its carrying value due to the short-term to maturity, and is considered a Level 1 measurement.

- **Accounts receivable, net, and accounts payable and accrued liabilities:** The fair value of accounts receivable, net, and accounts payable and accrued liabilities approximate their carrying value due to their short term to maturity.

- **Long term debt:** The fair value of long-term debt approximates its carrying value as it in-part bears a floating rate of interest and is of a shorter duration of up to 2 years.

- **Corporate Credit Facility:** The recorded value of the corporate credit facility approximates its fair value, due to its floating rate structure based on prime plus a spread, secured interest, and short term to maturity.

There were no transfers between levels of the fair value measurement hierarchy during the year.

The following tables set forth by level within the fair value hierarchy the Company's financial instruments, which were accounted for at fair value on a recurring basis as of December 31, 2022 and 2021:

	Fair Value Measurements as at December 31, 2022 using		
	Level 1	Level 2	Level 3
Assets (liabilities):			
Commodity derivatives	-	**$ 3,077,079**	-
Interest rate derivatives	-	**-**	-
Total	-	**$ 3,077,079**	-

	Fair Value Measurements as at December 31, 2021 using		
	Level 1	Level 2	Level 3
Assets (liabilities):			
Commodity derivatives	-	**$ (20,424,601)**	-
Interest rate derivatives	-	**43,421**	-
Total	-	**$ (20,381,180)**	-

Non-Financial Assets and Liabilities

Certain non-financial assets and liabilities are subject to fair value measurements. In those cases, the fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances.

For the impairment assessment of evaluated oil and gas properties, the ceiling test requires an estimate of the fair value of the unevaluated and unproved properties that are included in costs being amortized (Note 2). The fair value may be estimated using comparable market data, forecasted cashflows, or a combination of both as considered appropriate based on the circumstances. Given the significance of the unobservable nature of a number of the inputs, these are considered Level 3 on the fair value hierarchy.

Fair values are also estimated in connection with the initial measurement of ARO. Given the significance of the unobservable nature of a number of the inputs, this measurement is considered Level 3 on the fair value hierarchy (Note 2).

While the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value.

18. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The future results of the Company's crude oil and natural gas operations will be affected by market prices of crude oil and natural gas which is affected by numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and natural gas liquid products, economic disruptions, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company's operations are also subject to concentration risk due to the fact that all of its oil and natural gas revenue is sourced from its operations in the United States. Further, three of the Company's customers reflect 91.25% of its oil and gas revenues, with each of these customers representing 49.8%, 31.4%, and 10.0% of the revenues, which represents further concentration risk in specific customers.

Credit Risks

Financial instruments which potentially subject the Company to credit risk consist principally of cash balances, accounts receivable, and derivatives.

The Company maintains cash balances at financial institutions, which may at times exceed the federally insured limits. The Company has not experienced any significant losses from such investments, and the Company believes the credit quality of the financial institutions to be high.

The Company's accounts receivables are subject to normal industry credit risk. The accounts receivables are mainly due from participants in the oil and gas industry, who may be affected by periodic downturns in the economy, in general, or in their specific segment of the crude oil or natural gas industry. The Company believes that its level of credit-related losses due to such economic fluctuations have been immaterial.

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

Commodity Price Risk and Interest Rate Risk

The Company utilizes various commodity price derivative instruments to reduce commodity price risk being the risk that future cash flows will fluctuate as a result of changes in commodity prices. In addition, from time to time the Company utilizes interest rate swaps to mitigate exposure to changes in interest rates on the Company's variable rate indebtedness.

All derivative instruments are recorded in the Company's consolidated balance sheet as either assets or liabilities measured at their fair value (Note 2). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. The changes in the fair value are recognized in the Company's consolidated statements of operations and comprehensive income (loss).

The location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations and comprehensive income (loss) are as follows:

Year ended December 31,	Statements of Operations Location		**2022**		2021
Commodity derivative contracts					
Unrealized gain (loss)	Gain / (loss) on derivative instruments	**$**	**26,246,351**	$	(15,903,217)
Realized gain (loss)	Gain / (loss) on derivative instruments		**(36,269,846)**		(17,622,236)
Total gain (loss), net		**$**	**(10,023,495)**	$	(33,525,453)
Interest rate derivative contracts					
Unrealized gain	Finance and interest expense	**$**	**-**	$	43,421
Realized gain	Finance and interest expense		**623,579**		-
Total gain (loss), net		**$**	**623,579**	$	43,421

Gains and losses on derivative instruments are included in the operating section of the consolidated statements of cash flows.

The open commodity derivative positions as at December 31, 2022, are as follows, for the settlement periods presented:

	2023	2024	2025	Total Volumes
Crude Oil:				
WTI NYMEX - Swaps:				
Volumes (Bbl)	542,548	286,150	129,642	958,340
Weighted Average Price ($/Bbl)	$ 69.79	$ 65.97	$ 58.98	
Natural Gas and Natural Gas Liquids:				
Natural Gas NYMEX - Swaps:				
Volumes (MMBtu)	5,306,902	2,606,643	1,331,415	9,244,960
Weighted Average Price ($/MMBtu)	$ 5.43	$ 5.43	$ 5.33	
Natural Gas NYMEX vs. Houston Ship Channel - Basis Swaps:				
Volumes (MMBtu)	465,214	325,088	177,009	967,311
Weighted Average Price ($/MMBtu)	$ (0.07)	$ (0.07)	$ (0.07)	
Mont Belvieu Natural Gas - Swaps:				
Volumes (Gal)	1,560,711	857,027	326,472	2,744,210
Weighted Average Price ($/Gal)	$ 1.30	$ 1.57	$ 1.65	
Mont Belvieu Ethane - Swaps:				
Volumes (Gal)	5,818,913	3,195,317	1,217,209	10,231,439
Weighted Average Price ($/Gal)	$ 0.30	$ 0.34	$ 0.36	
Mont Belvieu Propane - Swaps:				
Volumes (Gal)	3,466,691	1,903,650	725,170	6,095,511
Weighted Average Price ($/Gal)	$ 0.80	$ 0.92	$ 0.95	
Mont Belvieu Isobutane - Swaps:				
Volumes	673,486	369,828	140,880	1,184,194
Weighted Average Price ($/Gal)	$ 0.89	$ 1.06	$ 1.10	
Mont Belvieu N. Butane - Swaps				
Volumes	1,426,461	783,308	298,388	2,508,157
Weighted Average Price ($/Gal)	$ 0.87	$ 1.04	$ 1.08	

The Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. As of December 31, 2022, the Company had interest rate swaps with a total notional amount of $nil (December 31, 2021 - $25,237,409).

The asset and liability fair values of the Company's derivative assets (liabilities), presented on the consolidated balance sheets is as follows:

As at December 31,	**2022**	2021
Derivative Assets:		
Current assets	**$ 2,019,600**	$ -
Noncurrent assets	**1,057,479**	-
Total Derivative Assets:	**$ 3,077,079**	$ -
Derivative Liabilities:		
Current liabilities	**$ -**	$ 6,479,508
Noncurrent liabilities	**-**	13,901,672
Total Derivative Liabilities:	**$ -**	$ 20,381,180

Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities as they become due.

At December 31, 2022 the Company had negative working capital of $162,980,101. The Company expects to repay its financial liabilities in the normal course of operations and to fund future operational and capital requirements through operating cash flows and through issuance of debt and/or equity.

The Company may need to conduct asset sales and/or issuances of debt and/or equity if liquidity risk increases in a given period. The Company believes it has sufficient funds to meet foreseeable obligations by actively monitoring its credit facilities through use of the loans, asset sales, and coordinating payment and revenue cycles.

The Company is required to meet certain financial covenants under its debt facilities (Note 7). As at December 31, 2022, the Company was not in breach of financial covenants.

19. COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, the Company may be involved in various legal proceedings and subject to claims that arise. Although the results of litigation and claims are inherently unpredictable and uncertain, we are not currently a party to any legal proceedings the outcome of which, if determined adversely to us, are believed to, either individually or taken together, have a material adverse effect on our business, financial condition or results of operations.

The Company has certain commitments under leases as outlined in Note 5. The Company also entered into a transportation agreement in 2022 for the transport of natural gas on a take-or-pay basis for a minimum agreed on volume, reflecting fees of approximately $11,000 per day.

20. FINANCE AND INTEREST EXPENSE

The amount of each significant category of finance and interest expense recognized, are as follows:

Year ended December 31,		**2022**		2021
Interest expense on long term debt	**$**	**11,389,415**	$	3,612,929
Interest expense for Corporate Credit Facility		**1,736,868**		-
Interest on asset back preferred		**658,047**		1,857,351
Interest on promissory notes		**-**		300,685
Interest rate derivative loss (gain)		**(623,579)**		(43,421)
Interest income		**(14,966)**		-
Bank fees and other		**282,548**		-
Total finance and interest expense	**$**	**13,428,333**	$	5,727,544

21. GENERAL AND ADMINISTRATIVE EXPENSE

The amount of each significant category of general and administrative expense recognized, are as follows:

Year ended December 31,		**2022**		2021
Stock based compensation expense	**$**	**10,197,720**	$	14,478,776
Employee salaries and benefits		**10,193,583**		6,483,720
Professional, legal, and advisory		**4,672,072**		3,629,525
Travel and accommodation		**278,653**		174,769
Software		**462,754**		344,577
Operating lease and variable lease costs		**215,487**		75,170
Office and administration		**986,558**		251,246
Recoveries		**(916,667)**		(416,666)
Total general and administrative expense	**$**	**26,090,160**	$	25,021,117

22. SUPPLEMENTAL CASH FLOW DISCLOSURES

Year ended December 31,		2022		2021
Supplementary cash flow information				
Cash paid for interest	**$**	**7,903,446**	$	2,278,570
Cash paid for income taxes		**-**		-
Non-Cash Investing Activities				
Property, plant and equipment non-cash accruals	**$**	**43,487,444**	$	15,752,315
Capitalized asset retirement obligations		**110,480**		217,471
Acquisition of oil and natural gas properties via share issuance		**-**		3,499,995
	$	**43,597,924**	$	19,469,781
Non-Cash Financing Activities				
Redemption of Redeemable NCI via issuance of Redeemable NCI	**$**	**100,727,774**	$	14,095,702
Redemption of Redeemable NCI via issuance of Origination Member Units		**15,581,968**		1,192,893
Redemption of Redeemable NCI via oil and gas property disposition		**542,584**		-
Redemption of promissory notes vis equity issuance		**-**		6,775,000
	$	**116,852,326**	$	22,063,595
Changes in Operating Assets and Liabilities				
Accounts receivable, net	**$**	**(7,668,573)**	$	(12,675,672)
Prepaid expenses		**(540,223)**		(510,063)
Accounts payable and accrued liabilities		**4,699,365**		19,986,246
Asset backed preferred instrument accrued interest		**-**		1,857,351
Asset retirement obligation settlements		**(127,862)**		-
Operating lease asset		**(235,564)**		-
Operating leases liability		**103,302**		9,542
	$	**(3,769,555)**	$	8,667,404

23. SUBSEQUENT EVENTS

Completion of DP5 and Creation of Development Partnership 7 ("DP7")

On January 20, 2023, the Company redeemed redeemable non-controlling interests with a redemption value of $36,354,869. In connection with this redemption, DP5 units with a redemption value of $2,505,631 were exchanged for 499,794 Class B non-voting units of Origination.

On January 20, 2023, the Company also formed DP7, with 24 external limited partners and Origination as a limited partner and the general partner. The intention of the DP7 is to finance the drilling and completion of five wells, with external partners funding approximately 60% and the Company funding 40%. The Company raised $34,262,236 from external limited partners of which $4,946,981 was raised from officers and directors of the Company. Investors participated $20,478,084 in Flat Payout Units and $13,784,152 in IRR Payout Units.

Dividends:

On January 3, 2023, the Company's board of directors declared a dividend of $0.0315 per SVS and PVS, and $3.15 per MVS. Payable on January 31, 2023, to shareholders of record on the close of business on January 17, 2023.

On February 1, 2023, the Company's board of directors declared a dividend of $0.0315 per SVS and PVS, and $3.15 per MVS. Payable on February 28, 2023, to shareholders of record on the close of business on February 14, 2023.

Corporate Credit Facility Covenant Waiver

In March 2023, the Company received a waiver of all covenants on the Corporate Credit Facility until July 1, 2023, and received a waiver on certain covenants on the ABS Facility until July 1, 2023. The Company also received an extension on the initial maturity date of Tranche 1 under the ABS Facility until July 1, 2023. In the absence of a covenant waiver, a breach of the covenant would result in the Corporate Credit Facility and/or ABS Facility to be due on demand.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Results of Operations

Oil and natural gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest, and other contractual provisions. Production expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies, and fuel consumed. Production taxes include production and severance taxes. Depletion of crude oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts. The results of operations for the Company's oil and natural gas production activities are provided in the Company's related statements of operations and comprehensive income (loss).

Costs Incurred and Capitalized Costs

The costs incurred in oil, natural gas, and NGL acquisition, exploration and development activities are as follows:

For the year ended December 31,		2022		2021
Unevaluated property acquisition	$	**2,244,517**	$	6,200,745
Development		**248,185,340**		68,323,942
Exploration costs		**5,179,046**		1,406,101
Total	$	**255,608,903**	$	75,930,788

Capitalized costs for unproved and unevaluated properties that are excluded from depletion is disclosed in Financial Statement Note 4 Oil and Natural Gas Properties, Net.

Oil and Natural Gas Reserves Data

Information with respect to the Company's oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by W.D. Von Gonten Engineering LLC as of January 1, 2023, the Company's third-party independent reserve engineers, based on information provided by the Company.

The following tables present the Company's estimates of its proved oil and natural gas reserves, net of royalties. The Company emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	Oils (Mbbl)	**Natural Gas (MMcf)**	**NGLs (Mbbl)**	**Total MBOE**
Total proved reserves at December 31, 2020	5,209	23,505	5,156	14,283
Revisions of previous estimates, and other	(2,445)	5,415	(3,550)	(5,093)
Improved recovery	1,715	6,201	1,220	3,969
Production	(743)	(2,398)	(358)	(1,501)
Total proved reserves at December 31, 2021	3,735	32,724	2,469	11,658
Revisions of previous estimates, and other	(1,850)	(27,505)	(1,271)	(7,705)
Extensions, discoveries and other additions	2,281	93,381	1,930	19,775
Improved recovery	1,111	14,069	671	4,127
Production	(1,030)	(13,317)	(588)	(3,838)
Total proved reserves at December 31, 2022	4,247	99,352	3,211	24,017
Proved Developed Reserves:				
December 31, 2020	2,275	6,672	1,692	5,079
December 31, 2021	2,137	7,468	1,041	4,423
December 31, 2022	3,973	70,480	2,962	18,682
Proved Undeveloped Reserves:				
December 31, 2020	2,934	16,833	3,464	9,204
December 31, 2021	1,598	25,256	1,428	7,235

December 31, 2022	274	28,872	249	5,335

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

Notable changes in proved reserves for the year ended December 31, 2022 included the following:

- Extensions and Discoveries: In 2022, total extensions and discoveries of 19.78 million BOE were primarily attributable to successful drilling in the Giddings Field, Austin Chalk and Hawkville Field, Austin Chalk, as well as the addition of proved locations. Included in these discoveries were 5.60 million BOE as a result of successful drilling in the Giddings Austin Chalk, the addition of 1.16 million BOE of additional proved locations and 7.25 million BOE attributable to the successful drilling in the Hawkville Austin Chalk and Eagle Ford and the addition of 5.70 million BOE as a result of additional proved locations.

- Improved Recoveries: In 2022, additions of proved reserves of 3.97 million BOE were primarily due to the managing of existing proved developed locations and an increase of projected recoverable volumes.

Notable changes in proved reserves for the year ended December 31, 2021 included the following:

- Revisions to Previous Estimates - In 2021, revisions to previous estimates decreased proved reserves. These revisions were adjusted downward caused by the removal of undeveloped locations from the previous year's development schedule in the Giddings Austin Chalk area.

- Improved Recovery - In 2021, additions to proved reserves of 4.13 million BOE were primarily due to the optimization of existing proved developed locations, via additional improvement projects, and an increase of projected recoverable volumes.

Standardized Measure of Discounted Future Cash Flows

The following table presents a standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves. The changes in the standardized measure of discounted future net cash flows relating to proved crude oil and natural gas were prepared in accordance with the provisions of ASC 932 *Extractive Activities - Oil and Gas*.

The standardized measure of discounted future net cash flows is computed by applying average prices for the last 12 months to estimated future production, year-end costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The Company believes the standardized measure does not provide a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. Actual future cash inflows may vary considerably.

For the year ended December 31,	**2022**	2021
Future cash inflows	$ 1,092,307,120	$ 247,313,824
Future production costs	(136,423,094)	(53,266,494)
Future development and abandonment costs	(75,501,920)	(3,124,700)
Future income tax expense	(98,092,314)	(24,496,630)
Future net cash inflows	$ 782,289,792	$ 166,426,000
10% annual discount for estimated timing of cash flows	(303,833,120)	(55,888,400)
Standardized measure of discounted future net cash flows	$ 478,456,672	$ 110,537,600

The twelve-month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the Company's reserves. The price of other liquids is included in natural gas. The prices for the Company's reserve estimates were as follows:

	Oil (Mbbl)	Natural Gas (MMcf)	NGLs (Mbbl)
December 31, 2022	$ 94.49	$ 6.25	$ 32.62
December 31, 2021	$ 66.55	$ 3.64	$ 27.29

Changes in the standardized measure of discounted future net cash flows at 10% per annum are estimated as follows:

For the year ended December 31,	2022	2021
Beginning of period	$ 110,537,600	$ 82,028,564
Sales of oil and natural gas produced, net of production costs	(81,065,058)	(26,623,743)
Extensions, discoveries and other additions	200,494,177	(12,803,556)
Previously estimated development cost incurred during the period	(3,124,700)	14,038,000
Net change of prices and production costs	139,967,308	114,050,543
Change in future development and abandonment costs	(57,466,319)	48,932,984
Revisions of quantity and timing estimates	225,544,516	(120,961,889)
Accretion of discount	(760,264)	18,575,522
Change in income taxes	(55,419,410)	8,768,285
Other	(251,178)	(15,467,110)
End of period	$ 478,456,672	$ 110,537,600

ALPINE SUMMIT ENERGY PARTNERS, INC. ANNUAL REPORT

Alpine Summit Energy Partners, Inc. Board of Directors and Executive Officers as of March 31, 2023

BOARD OF DIRECTORS	
Name	**Principal Occupation or Employment**
Craig Perry	Chairman of the Board of Directors, Alpine Summit Energy Partners, Inc. Chief Executive Officer, Alpine Summit Energy Partners, Inc.
Stephen Schaefer	Founder of Schaefer Advisory
Porter Collins	Co-Founder and Portfolio Manager at Seawolf Capital
Agenia Clark	President and Chief Executive Officer of the Girl Scouts of Middle Tennessee
James Russo	Self-Employed Investor

EXECUTIVE OFFICERS	
Name	**Principal Occupation or Employment**
Craig Perry	Chief Executive Officer
William Wicker	Chief Investment Officer
Michael McCoy	Chief Operating Officer
Darren Moulds	Chief Financial Officer
Reagan Brown	Chief Administrative Officer
Chrystie Holmstrom	Chief Legal Officer and Corporate Secretary
Chris Nilan	Senior Managing Director of Capital Markets