ALVOPETRO ENERGY LTD.

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2025

DATED MARCH 17, 2026

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SCHEDULES

SCHEDULE A - REPORT ON RESERVES DATA, CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOUCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR (FORM 51-101F2), EFFECTIVE DECEMBER 31, 2025

SCHEDULE B - DISCLOSURE OF CONTINGENT AND PROSPECTIVE RESOURCE DATA EFFECTIVE DECEMBER 31, 2025

SCHEDULE C – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-101F3)

SCHEDULE D – AUDIT COMMITTEE MANDATE

DEFINITIONS AND ABBREVIATIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**2025 Loan**" means the $20 million loan agreement entered into on November 28, 2025 by Alvopetro S.A. Extração de Petróleo e Gás Natural with Itaú BBA International plc.

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9 (Alberta);

"**AIF**" or "**Annual Information Form**" means this annual information form;

"**Alvopetro**", "**the Corporation**" or "**the Company**" means Alvopetro Energy Ltd., a corporation existing under the laws of the Province of Alberta;

"**ANP**" means Agência Nacional do Petróleo, Gás Natural e Biocombustíveis, or National Agency of Petroleum, Natural Gas and Biofuels, an agency of the Brazilian government;

"**Arrangement**" means the arrangement pursuant to Section 193 of the ABCA involving Petrominerales, Pacific Rubiales Energy Corp., Alvopetro and the shareholders of Petrominerales;

"**Board**" or "**Board of Directors**" means the board of directors of Alvopetro as it may be comprised from time to time;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary chapter) as amended from time to time;

"**Common Shares**" means the common shares in the capital of Alvopetro;

"**GLJ**" means GLJ Ltd., independent oil and natural gas reservoir engineers;

"**GLJ Reserves and Resources Report**" means the independent reserves and resources assessment and evaluation dated February 25, 2026 and effective December 31, 2025 prepared by GLJ evaluating the oil, NGLs and natural gas reserves attributable to the Corporation as well as the contingent and prospective resources of the Corporation's Murucututu natural gas field;

"**GSA**" means the long-term gas sales agreement entered into on April 18, 2018 and amended May 1, 2020, February 2, 2021, December 23, 2021, December 29, 2022, December 15, 2023 and December 13, 2024 between Alvopetro S.A. Extração de Petróleo e Gás Natural, the Company's wholly-owned subsidiary, and Bahiagás, the natural gas distribution company in Bahia State;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**Petrominerales**" means Petrominerales Ltd.;

"**Shareholders**" means the holders from time to time of Common Shares, collectively or individually, as the context requires;

"**Tax Act**" means the *Income Tax Act*, R.S.C. 1985, c.1 (5th Supp.) and the regulations made thereunder, as now in effect and as they may be promulgated or amended from time to time;

"**TSXV**" means the TSX Venture Exchange; and

"**United States**" or "**U.S.**" means the United States of America, its territories and possessions, any state of the United States, and the District of Columbia.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. **Except as otherwise indicated, all dollar amounts set forth in this Annual Information Form are in United States dollars and references to $ are to United States dollars**. References to C$ are to Canadian dollars.

ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbl/d	barrels per day
Mbbls	one thousand barrels
MMbbls	one million barrels
bopd	barrels of oil and natural gas liquids per day
NGL	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcfpd	thousand cubic feet per day
MMcfpd	million cubic feet per day
MMBtu	million British Thermal Units
boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
Mboe	thousands of barrels of oil equivalent
MMboe	millions of barrels of oil equivalent
Bcf	billion cubic feet

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Mcf	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls	6.2898
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

Other

BOE or boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas
Mcfe	thousand cubic feet of gas equivalent on the basis of 6 Mcfe to 1 barrel of oil
m^3	cubic metre
m^3/d	cubic metre per day
C$	Canadian dollars
R$	Brazilian real
USD	U.S. dollars
$	U.S. or United States dollars
$000s	Thousands of U.S. or United States dollars

NON-GAAP AND OTHER FINANCIAL MEASURES

This AIF makes reference to various non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures as such terms are defined in National Instrument 52-112 – *Non-GAAP and Other Financial Measures Disclosure*. Such measures are not recognized measures under GAAP and do not have a standardized meaning prescribed by IFRS Accounting Standards ("IFRS") and therefore might not be comparable to similar financial measures disclosed by other issuers. While these measures may be common in the oil and gas industry, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. The non-GAAP and other financial measures referred to in this report should not be considered an alternative to, or more meaningful than measures prescribed by IFRS and they are not meant to enhance the Company's reported financial performance or position. These are complementary measures that are used by management in assessing the Company's financial performance, efficiency and liquidity and they may be used by investors or other users of this document for the same purpose. For more information with respect to financial measures which have not been defined by GAAP, including reconciliations to the closest comparable GAAP measure, see the "*Non–GAAP and Other Financial Measures*" section of the Corporation's management discussion and analysis accompanying its most recent audited annual financial statements which are available on SEDAR+ at sedarplus.ca.

Below is a description of the non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures used in this AIF.

Non-GAAP Financial Measures

Operating netback

Operating netback is calculated as natural gas, oil and condensate sales revenues less royalties and production expenses. Operating netback is a common metric used in the oil and gas industry to demonstrate profitability from operations. For a computation of operating netback, see the table entitled "Average Daily Production Volume, Prices Received, Royalties Paid, Production Costs and Netback –Natural Gas, Light & Medium Crude Oil and Natural Gas Liquids (NGLs)" in the section entitled "*Statement of Reserves Data and Other Oil and Gas Information*".

Non-GAAP Financial Ratios

Operating netback per boe

Operating netback is calculated on a per unit basis, which is per barrel of oil equivalent ("boe"). It is a common non-GAAP financial measure used in the oil and gas industry and management believes this measurement assists in evaluating the operating performance of the Company and when reported on a per unit basis is a non-GAAP ratio. It is a measure of the economic quality of the Company's producing assets and is useful for evaluating variable costs as it provides a reliable measure regardless of fluctuations in production. Alvopetro calculated operating netback per boe as operating netback divided by total sales volumes (barrels of oil equivalent). For a computation of operating netback and operating netback per boe, see the table entitled "Average Daily Production Volume, Prices Received, Royalties Paid, Production Costs and Netback –Natural Gas, Light & Medium Crude Oil and Natural Gas Liquids (NGLs)" in the section entitled "*Statement of Reserves Data and Other Oil and Gas Information*".

Capital Management Measures

Funds flow from operations

Funds flow from operations is a non-GAAP capital management measure that includes all cash generated from operating activities and is calculated before changes in non-cash working capital. The most comparable GAAP measure to funds flow from operations is cash flows from operating activities. Management considers funds flow from operations important as it helps evaluate financial performance and demonstrates the Company's ability to generate sufficient cash to fund future growth opportunities. Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flows from operating activities however management finds that the impact of working capital items on the cash flows reduces the comparability of the metric from period to period.

Working capital

Working capital is computed as current assets less current liabilities. Working capital is a measure of liquidity and is used to evaluate financial resources.

Working capital, net of debt

Working capital net of debt is computed as net working capital decreased by the balance of any non-current bank debt or other loans. Working capital net of debt is used to assess the overall financial position of the Company as well as to evaluate financial resources.

Supplementary Financial Measures

"Average realized natural gas price - $/Mcf" is comprised of natural gas sales as determined in accordance with IFRS, divided by the Company's natural gas sales volumes.

"Average realized NGL – condensate price - $/bbl" is comprised of condensate sales as determined in accordance with IFRS, divided by the Company's NGL sales volumes from condensate.

"Average realized oil price - $/bbl" is comprised of oil sales as determined in accordance with IFRS, divided by the Company's oil sales volumes.

"Averaged realized price - $/boe" is comprised of natural gas, condensate and oil sales as determined in accordance with IFRS, divided by the Company's total natural gas, NGL (condensate) and oil sales volumes (barrels of oil equivalent).

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the total natural gas, NGL (condensate) and oil sales volumes (barrels of oil equivalent).

"Production expenses per boe" is comprised of production expenses, as determined in accordance with IFRS, divided by the total natural gas, condensate and oil sales volumes (barrels of oil equivalent).

"Transportation expenses per boe" is comprised of transportation expenses, as determined in accordance with IFRS, divided by the total natural gas, NGL (condensate) and oil sales volumes (barrels of oil equivalent).

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of natural gas, oil, and NGL reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of the Corporation's natural gas and petroleum reserves does not represent the fair market value of the Corporation's reserves.

Caution Respecting BOE and Mcfe

In this AIF, the abbreviation boe means barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas when converting natural gas to boes. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is different than the energy equivalency conversion ratio of 6 Mcf to 1 boe, utilizing a conversion ratio of 6 Mcf to 1 boe may be misleading as an indication of value.

In this AIF, the abbreviation Mcfe means thousand cubic feet of gas equivalent on the basis of 6 Mcfe to 1 barrel of oil when converting oil to Mcfes. Mcfes may be misleading, particularly if used in isolation. An Mcfe conversion ratio of 6 Mcfe to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is different than the energy equivalency conversion ratio of 6 Mcfe to 1 bbl, utilizing a conversion ratio of 6 Mcfe to 1 bbl may be misleading as an indication of value.

Definitions

Certain terms used in this AIF in describing reserves and resources and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"possible reserves" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities" (which refers to the lowest level at which reserves calculations are performed) and to "Reported Reserves" (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- a least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories as follows:

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing as follows:

"**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Interests in Reserves, Production, Wells and Properties

"**gross**" means: (a) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (b) in relation to wells, the total number of wells in which an issuer has an interest; and (c) in relation to properties, the total area of properties in which an issuer has an interest.

"**net**" means: (a) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (b) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (c) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

"**working interest**" means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, which interest gives the issuer the right to explore for, develop, produce and market the leased substances on the property (lease).

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

Resources

Definitions

"**Total Petroleum Initially-In-Place (PIIP)**" is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

"**Discovered Petroleum Initially-In-Place**" (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

> "**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status. Reserves are further defined above in "*Reserves*" section.
>
> "**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

"**Undiscovered Petroleum Initially-In-Place**" (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

> "**Prospective Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity.

Uncertainty Categories for Resources Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

> **Low Estimate**: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
>
> **Best Estimate:** This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
>
> **High Estimate:** This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are

used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production.

Discovered and Commercial Status and Risks Associated with Resources Estimates

<u>Discovery Status</u>

Total petroleum initially in place is first subdivided based on the discovery status of a petroleum accumulation. Discovered PIIP, production, reserves, and contingent resources are associated with known accumulations. Recognition as a known accumulation requires that the accumulation be penetrated by a well and have evidence of the existence of petroleum.

<u>Commercial Status</u>

Commercial status differentiates reserves from contingent resources. The following outlines the criteria that should be considered in determining commerciality:

- economic viability of the related development project;
- a reasonable expectation that there will be a market for the expected sales quantities of production required to justify development;
- evidence that the necessary production and transportation facilities are available or can be made available;
- evidence that legal, contractual, environmental, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated;
- a reasonable expectation that all required internal and external approvals will be forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approvals for expenditures, etc.;
- evidence to support a reasonable timetable for development. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a maximum time frame for classification of a project as commercial, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives.

Commercial Risk Applicable to Resources Estimates

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources, and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality." The chance of commerciality varies in different classes of recoverable resources as follows:

Reserves: To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.

Contingent Resources: Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

Prospective Resources: Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components — the chance of discovery and the chance of development.

Economic Status of Resources Estimates

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to subclassify contingent resources by economic status:

> Economic Contingent Resources are those contingent resources that are currently economically recoverable.
>
> Sub-Economic Contingent Resources are those contingent resources that are not currently economically recoverable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is “undetermined” (i.e., “contingent resources – economic status undetermined”).

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e., specified economic conditions, which are generally accepted as being reasonable (refer to COGE Handbook Section 1.3.7).

Project Maturity Sub-Classes for Contingent Resources

> Development Pending: Where resolution of the final conditions for development is being actively pursued (high chance of development).
>
> Development On Hold: Where there is a reasonable chance of development but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.
>
> Development Unclarified: When the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties.
>
> Development Not Viable: Where no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

Use of Unrisked Estimates

The unrisked estimates of prospective resources referred to in this Annual Information Form and the schedules attached hereto have not been risked for either the chance of discovery or the chance of development. There is no certainty that any portion of the prospective resources will be discovered and even if discovered, there is no certainty that it will be commercially viable to produce any portion. The unrisked estimates of contingent resources referred to in this Annual Information Form have not been risked for the chance of development. There is no guarantee that the estimated resources will be recovered and there is uncertainty that it will be commercially viable to produce any portion of the resources. See “*Resources*” above for further details and Schedule B - Disclosure of Contingent and Prospective Resource Data Effective December 31, 2025 for details regarding risked estimates.

FORWARD-LOOKING STATEMENTS

Certain statements or disclosures contained in this Annual Information Form constitute forward-looking statements. The use of any of the words “anticipate”, “believe”, “continue”, “estimate”, “expect”, “forecast”, “intend”, “may”, “will”, “plan”, “project”, “should”, “believe” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form may contain forward-looking statements and information pertaining to the following:

- corporate strategy and anticipated financial and operational performance;
- the size of, and future net revenues from natural gas, oil, NGLs and reserves and resources of the Corporation;
- the arbitration of Alvopetro's working interest in the Caburé natural gas field;
- the dispute with holders of a gross-overriding royalty on certain assets of the Corporation;
- the performance characteristics of the Corporation's properties and projected/future natural gas, oil, and NGL production and sales levels;
- planned capital expenditures, including the timing thereof, costs and the method of funding;
- projections of commodity prices and costs;
- the anticipated outcomes of regulatory determinations and timing of receipt of regulatory approvals;
- expectations regarding the anticipated timing of completion of the expansion of the Corporation's gas treatment facility;
- expectations regarding the ability to fund planned expenditures, repay amounts borrowed and raise capital;
- anticipated timing of closing dispositions of certain assets of the Corporation, including the timing of receipt of regulatory approvals associated with such disposition;
- supply and demand for natural gas, oil and NGLs;
- timing of development of undeveloped reserves;
- the Corporation's reinvestment and stakeholder return model including plans for the future payments of dividends;
- estimated volumes of gross and net production in 2026 and future years;
- tax horizon and future tax rates enacted in the Company's areas of operations;
- expectations with respect to the expiration of rights to explore, develop and exploit Alvopetro's properties and the Corporation's ability to obtain permits, contract extensions or fulfill the required contractual obligations to retain such rights;
- estimated abandonment and reclamation costs, and timing of such;
- Alvopetro's expectations regarding the development and production potential of its properties including the Corporation's working interest of such properties;
- expected trends in environmental regulation, including the anticipated impact the trends may have on operations and compliance costs;
- intentions with respect to the implementation of programs that support an environmental management system and attempts to manage and mitigate the environmental impact of Alvopetro's operations;
- treatment under governmental regulatory regimes and tax and royalty laws; and
- expectations that the Company does not have material reorganizations planned.

With respect to forward looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding:

- estimated future natural gas, NGL and oil production and sales levels;
- the success of the Corporation's operations and exploration and development activities;
- prevailing commodity prices and foreign exchange rates;
- the timing and amount of capital expenditures and operational expenditures including the impacts of anticipated inflation rates;
- the timing and receipt of government approvals and permits, where required;
- compliance with and liabilities under environmental laws and regulations;
- compliance with debt covenants associated with the 2025 Loan;
- general economic and financial market conditions;
- the ability of the Company to secure additional financing sources to fund planned expenditures if required;
- the ability of the Corporation to secure necessary personnel, equipment and services;
- the outcomes of any redeterminations of Alvopetro's working interest on the unitized area which includes Alvopetro's Caburé natural gas field;
- the outcomes of any arbitrations, negotiations, legal actions or disputes involving the Corporation; and
- government regulation in the areas of taxation, royalty rates and environmental protection.

The actual results, performance or achievements of the Corporation may differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth under the heading "Risk Factors" and elsewhere in this Annual Information Form including:

- uncertainties with respect to the outcome of the arbitration of Alvopetro's working interest in the Caburé natural gas field and the associated impact on future revenues, funds flow from operations and the overall financial position of the Company;
- uncertainties in estimating reservoir performance and natural gas, NGL and oil reserves and resources;
- exploration, development and production risks and uncertainties with respect to future reserve additions, acquisitions and replacement;
- volatility in market prices for natural gas, NGLs and oil including the impact of declines on such prices, as well as the impact on such prices as a result of international conflicts or other geopolitical events and the overall condition of the global economy as well as the impact on such prices as a result of the imposition of new or expanded tariffs imposed by domestic and foreign governments or the imposition of other restrictive trade measures, retaliatory or countermeasures implemented by such governments;
- uncertainties with respect to amounts owing under current disputes as well as the impact on future cash flows;
- economic dependence on one counterparty for the sale of natural gas;
- supply and demand conditions for natural gas within Brazil;
- the uncertainty of Alvopetro's ability to repay amounts borrowed and secure new debt or equity financing as needed;
- failure to obtain required approvals and permits from regulatory authorities, or failure to obtain such permits in a timely manner;
- the impact of inflation and supply chain disruptions;
- changes in or the introduction of new government regulations, including changes in tax laws, environmental laws and incentive programs relating to the oil and gas industry;
- volatility in foreign exchange rates;
- the outcome of negotiations, legal actions or disputes involving the Corporation or litigation brought against the Corporation;
- reliance on third party operators and personnel;
- the Company's ability to pay dividends and the Company's dividend policy;
- failure to obtain the anticipated benefits from new acquisitions or dispositions including uncertainties with respect to the anticipated timing of closing dispositions of certain assets of the Corporation, including the timing of receipt of regulatory approvals associated with such disposition;
- ability to manage expiries and other commitments and to successfully obtain extensions, suspensions or approvals as may be needed to manage the Company's assets;
- stock market volatility;
- impacts relating to general economic conditions in Canada, Brazil, the United States, and global markets;
- availability and cost of insurance;
- failure to commercialize discoveries;
- failure to implement projects on schedule;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- the impact of amendments to applicable tax legislation, including the Tax Act and Brazilian tax legislation, including regional tax incentives, on Alvopetro;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel and equipment;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, completion and processing challenges;
- changes in legislation, including changes in incentive programs relating to the oil and gas industry;
- unfavourable weather conditions (including climate change) and trends; and
- other factors discussed under the heading "Risk Factors".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. The Corporation does not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

ALVOPETRO ENERGY LTD.

Introduction

Alvopetro is a resource company engaged in the exploration, development and production of hydrocarbons in Brazil and in Canada.

On December 4, 2013, Alvopetro was listed on the TSXV under the symbol "ALV" and on December 5, 2013, the Common Shares commenced trading. On January 15, 2019 Alvopetro's common shares commenced trading on the OTCQX® Best Market, a U.S. market operated by OTC Markets Group (OTCQX: OTCM), under the symbol "ALVOF".

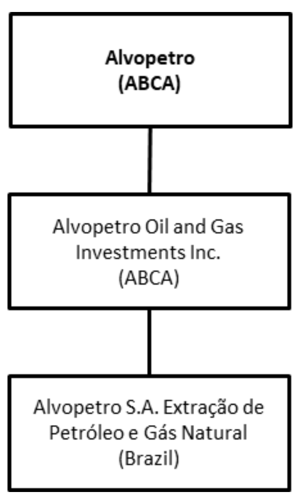
Name, Address and Incorporation

Alvopetro was incorporated under the ABCA on September 25, 2013 as "1774501 Alberta Ltd." On November 19, 2013, Alvopetro amended its articles to change its name to "Alvopetro Energy Ltd." On January 1, 2014 the Corporation amalgamated with 1765823 Alberta Ltd., a wholly-owned subsidiary, by way of articles of amalgamation and continued under the name "Alvopetro Energy Ltd."

The principal business office of Alvopetro is located at Suite 401, 255 – 17th Avenue SW, Calgary, Alberta, T2S 2T8 and the registered office of Alvopetro is located at Suite 4000, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

Intercorporate Relationships

The organizational structure of Alvopetro is as set out below. Alvopetro holds a 100% voting interest, either directly or indirectly, in each of its subsidiaries.



GENERAL DEVELOPMENT OF THE BUSINESS

History

Alvopetro was incorporated under the ABCA on September 25, 2013 as "1774501 Alberta Ltd." for the sole purpose of participating in the Arrangement between Alvopetro, Pacific Rubiales Energy Corp., Petrominerales and the shareholders of Petrominerales which was completed on November 28, 2013.

Three Year History

The following is a summary of significant events in the general development of the business of Alvopetro during the last three financial years ending December 31, 2023, December 31, 2024 and December 31, 2025.

2023

In 2023, average daily sales volumes decreased to 2,142 boepd (-16% from 2022) due to both reduced natural gas demand and lower available natural gas allocations from the Caburé natural gas field as Alvopetro's partner on the field increased production allocations in the year. Throughout 2022 and early 2023 Alvopetro was able to sell additional production volumes from the field above its working interest share as Alvopetro's partner was not utilizing its working share of production; however, in the second quarter of 2023, the partner increased their nominations from the field, reducing availability to Alvopetro.

Capital expenditures in 2023 were focused mainly on the Murucututu natural gas field and the Bom Lugar oil field. On Murucututu, Alvopetro stimulated the 197(1) well and drilled and completed the 183-A3 well. On Bom Lugar, Alvopetro drilled and completed the BL-06 well and upgraded field facilities. The 182-C2 exploration well on Block 182 was tested in early 2023. Additional capital expenditures included long-lead equipment inventory purchases for use on future wells. Impairment losses of $4.2 million and $6.7 million were recorded for Bom Lugar and Block 182, respectively.

The Company announced a 17% increase in its quarterly dividend payments to $0.14 per Common Share commencing in the first quarter of 2023. Total dividends of $0.56 per Common Share were declared in 2023 ($20.5 million).

Key Highlights:

- annual average natural gas, oil and NGL sales volumes of 2,142 boepd;
- realized natural gas sales price of $12.64/Mcf, an overall realized sales price of $76.33 per boe and an operating netback of $68.82 per boe;
- net income of $28.5 million, cash flows from operating activities of $47.7 million and funds flow from operations of $48.0 million; and
- capital expenditures of $27.4 million.

2024

Alvopetro's working interest in the unitized area (the "Unit") which includes the Caburé natural gas field was increased from the original 49.1% working interest to 56.2% effective June 1, 2024. The higher working interest increased Alvopetro's entitlement to reserves as further outlined in the section "*Statement of Reserves Data and Other Oil and Gas Information*" and Alvopetro's entitlement to natural gas production from the Unit increased to the new working interest. In addition, as Alvopetro's working interest exceeded 50% following the redetermination, Alvopetro was entitled to assume operatorship, which transitioned to Alvopetro in the third quarter of 2024. The redetermined working interest is under dispute and the matter is currently being reviewed by an arbitral tribunal pursuant to the Rules of Arbitration (the "Rules") of the International Chamber of Commerce ("ICC"). As of the date of this AIF, the outcome of the arbitration is uncertain and may have a material adverse effect on Alvopetro. For further analysis on the potential impact of the arbitration, refer to the sections entitled "*Risk Factors – Arbitration of Alvopetro's Working Interest*" and "*Legal Proceedings and Regulatory Actions*".

Average daily sales volumes decreased in 2024 to 1,794 boepd (-16% from 2023) due mainly to reduced natural gas demand. Capital expenditures included recompletions of the 183-A3 and 183(1) wells on the Murucututu field, a facilities upgrade project at the Caburé field to add a compression system, as well as costs to re-enter and side-track the 183-B1 well on Block 183. Capital expenditures also included historical costs for Unit development expenditures to increase Alvopetro's share from the 49.1% originally charged to the redetermined working interest of 56.2%.

The Company announced a 36% decrease in its quarterly dividend payments to $0.09 per Common Share commencing with the first quarter of 2024. Total dividends of $0.36 per Common Share were declared in 2024 ($13.2 million).

Key Highlights:

- annual average natural gas, oil and NGL sales volumes of 1,794 boepd;
- realized natural gas sales price of $11.42/Mcf, an overall realized sales price of $69.31 per boe and an operating netback of $60.99 per boe;
- net income of $16.3 million, cash flows from operating activities of $34.9 million and funds flow from operations of $33.3 million; and
- capital expenditures of $15.3 million.

2025

Alvopetro’s daily sales volumes increased to 2,523 boepd in 2025 (+41% from 2024) due mainly to the amended GSA agreed to with Bahiagás which came into effect on January 1, 2025. Key terms of the amended GSA are as follows:

- Increased Alvopetro's contracted firm reference volumes effective January 1, 2025 by 33% up to 400,000 m^3/d. The firm volume of 400,000 m^3/d (before any provisions for take or pay allowances) represents contracted volumes based on contract referenced natural gas heating value. Note that Alvopetro's reported natural gas sales volumes are prior to any adjustments for heating value of Alvopetro natural gas. For the year ended December 31, 2025, Alvopetro's natural gas was approximately 8% hotter than the contract reference heating value.
- Adjusted the natural gas pricing model to be recalculated quarterly (compared to semi-annually under previous terms) and to be a function of Brent oil equivalent prices and Henry Hub natural gas prices resulting in quicker adjustments for commodity price and foreign exchange rate fluctuations.
- Removed the contractual floor and ceiling provisions.
- Enhanced supply failure penalty mechanisms to reduce Alvopetro's exposure in the event of any supply failures.
- Retained existing take or pay provisions requiring Bahiagas to pay for any gas not taken to the extent deliveries are less than 80% of firm volumes monthly, or less than 90% annually.
- The updated contract extends to December 31, 2035.

On February 5, 2025, the Company announced that it had entered into a farmin agreement (the “Farmin”) with a private company in Canada. Under the terms of the Farmin, Alvopetro agreed to fund 100% of two earning wells in exchange for a 50% non-operated working interest in 19.13 sections of land (12,243 net acres) in Western Saskatchewan. The two (1.0 net) earning wells were drilled, completed and equipped in the first quarter of 2025 and sales commenced in mid-April. In the third quarter of 2025, an additional two (1.0 net) wells were drilled, completed and equipped and sales commenced in September 2025. In October 2025, Alvopetro entered into an expanded area of mutual interest (“Expanded AMI”) with the same partner, with Alvopetro agreeing to fund 100% of the costs for drilling two additional earning wells in exchange for a 50% working interest in an additional 47 sections of land (15,010 net acres). These two additional earning wells were drilled in the fourth quarter of 2025 and an additional two (1.0 net) wells were drilled in early 2026. One of the wells requires remediation and as of the date of this AIF, there are seven wells (3.5 net) on production.

On November 28, 2025, the Company’s wholly owned subsidiary, Alvopetro S.A. Extração de Petróleo e Gás Natural entered into the $20 million 2025 Loan. The 2025 Loan has a two-year term and bears interest at a fixed rate of 7% per annum (payable quarterly), including all applicable charges and fees. Repayments of the 2025 Loan will be made quarterly, commencing on November 30, 2026 and ending on November 29, 2027.

The Company announced a 11% increase in its quarterly dividend payments to $0.10 per Common Share commencing in the first quarter of 2025. The Company also declared an additional $0.02 per Common Share special dividend in the fourth quarter of 2025. Total dividends of $0.42 per Common Share were declared in 2025 ($15.4 million).

Key Highlights:

- annual average natural gas, oil and NGL sales volumes of 2,523 boepd, with 2,417 boepd from Brazil operations and 106 bopd from Canadian operations;
- realized natural gas sales price of $10.49 per Mcf, an overall realized sales price of $62.92 per boe and an operating netback of $52.61 per boe;
- net income of $23.1 million, cash flows from operating activities of $40.8 million and funds flow from operations of $40.6 million; and
- capital expenditures of $33.5 million.

Normal Course Issuer Bids

2023 Normal Course Issuer Bid

On January 3, 2023, Alvopetro announced the approval by the TSX Venture Exchange for a normal course issuer bid (the “2023 NCIB”). Pursuant to the 2023 NCIB, Alvopetro was authorized to repurchase up to 2,876,414 Common Shares, representing 7.9% of the Common Shares outstanding as of January 3, 2023, over the period commencing on January 6, 2023 and ending on the earlier of January 5, 2024 or such earlier date as the 2023 NCIB was completed or was terminated at the

Company's election. During 2023, Alvopetro repurchased a total of 4,600 Common Shares at an average price of C$6.76 per share. The shares were subsequently cancelled. No repurchases were made in 2024 and the 2023 NCIB terminated on the expiry date of January 5, 2024.

2024 Normal Course Issuer Bid

On August 12, 2024, Alvopetro announced the approval by the TSX Venture Exchange for a normal course issuer bid (the "2024 NCIB"). The terms of the 2024 NCIB permit Alvopetro to repurchase up to 2,953,044 Common Shares from August 13, 2024 to the earlier of August 12, 2025 or when the 2024 NCIB is completed or terminated by Alvopetro. During 2024, Alvopetro repurchased a total of 189,000 Common Shares at an average price of C$4.95 per share and during 2025, a total of 151,000 Common Shares were repurchased at an average price of C$5.22 per share. All shares purchased under the 2024 NCIB were subsequently cancelled. The 2024 NCIB expired on August 12, 2025.

Significant Acquisitions

Alvopetro did not complete any significant acquisitions during any of the years ended December 31, 2023, 2024 or 2025.

DESCRIPTION OF THE BUSINESS

Business

Alvopetro is engaged in the exploration for and the acquisition, development and production of hydrocarbons in Brazil and Canada. In Brazil, Alvopetro held interests in the Caburé natural gas field and the Murucututu natural gas field and one exploration asset (the western portion of Block 183) as of December 31, 2025 comprising 14,748 acres (gross and net). In Canada, as of December 31, 2025 Alvopetro held a 50% non-operated working interest in 75 sections of land (23,539 net acres) focused on the Mannville Stack heavy oil play fairway in Western Saskatchewan. As of the date of this AIF, Alvopetro holds a 50% non-operated working interest in 80.5 section of land (25,760 net acres) in Saskatchewan.

Strategy

Alvopetro is deploying a balanced capital allocation model where we seek to reinvest roughly half our cash flows into organic growth opportunities and return the other half to stakeholders. Alvopetro's organic growth strategy is to focus on the best combinations of geologic prospectivity and fiscal regime. Alvopetro is balancing capital investment opportunities in Canada and Brazil where we are building off the strength of our Caburé and Murucututu natural gas fields and the related strategic midstream infrastructure.

Specialized Skill and Knowledge

Exploration for and development of petroleum resources require specialized skills and knowledge, including in the areas of petroleum engineering, geophysics, and geology. The Corporation may face challenges in attracting and retaining employees, consultants and advisors to meet these needs. See "*Risk Factors*".

Competitive Conditions

The oil and gas industry is highly competitive, with respect to the acquisition of prospective oil and gas properties and reserves, in attracting financing sources for the acquisition of new reserves or the development of existing reserves, and in marketing production from existing reserves. Alvopetro's competitive position depends on its geoscience and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Alvopetro will compete with a substantial number of other companies having larger technical staff and greater financial and operational resources and access to capital. Many such companies not only engage in the acquisition, exploration, development and production of petroleum reserves, but also carry on refining operations and market refined products.

Cycles

Alvopetro's revenues are reliant on international commodity prices, which have fluctuated widely during recent years and are determined by worldwide supply and demand factors, including weather and general economic conditions. Although

Alvopetro’s business in Brazil is not seasonal, seasonality may impact demand and price for natural gas and may also impact the timing of operations as weather delays may affect the speed of completion of operations.

In 2025 the Company commenced activities in Canada. The level of oil and natural gas activity in Canada is influenced by seasonal factors. Wet weather and spring thaw may make the ground unstable. Consequently, municipal and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Seasonal factors and unexpected weather patterns may lead to declines in exploration, development and production activities.

Economic Dependence

In 2025 Alvopetro sold all natural gas from the Company’s Caburé and Murucututu natural gas fields to one counterparty. If the GSA was terminated for any reason or if Bahiagás was unable to accept all or a portion of natural gas production from Alvopetro, Alvopetro may be unable to enter into a relationship with another purchaser for such natural gas on a timely basis or on similar terms. Where demand from Bahiagás is reduced, future revenues may be reduced. See “*Risk Factors*” in this AIF for further information. Should Bahiagás not be able to make payments related to gas already delivered, Alvopetro’s accounts receivable and liquidity would be impacted.

Employees

As of December 31, 2025, Alvopetro employed 67 employees, including 59 in Brazil with the remainder in Calgary, Canada. Alvopetro may require additional employees and third-party consultants and contractors based on future operational and administrative demands.

Foreign Operations

During the year ended December 31, 2025, 96% of Alvopetro’s sales volumes were from its operations in Brazil which, despite its large economy, is still considered a developing country. To date, Alvopetro has benefitted from several initiatives provided by various levels of government in support of international oil and gas development in Brazil (See ”*Brazilian Government Initiatives*”). However, all oil and gas exploration, development and production activities are subject to significant political, economic, and other uncertainties and these risks are generally considered higher when operating in an emerging market. See “*Risk Factors*” in this Annual Information Form for further details.

Reorganizations

There have been no material reorganizations of the Company or any of its subsidiaries within the three most recently completed financial years or proposed for the current financial year. On December 31, 2023, Alvopetro completed a reorganization within Brazil, merging Alvopetro Investimentos e Participações Ltda. and Alvopetro Participações em Petróleo E Gás Ltda (collectively, the “Merged Entities”) into the operating company in Brazil, Alvopetro S.A. Extração de Petróleo e Gás Natural (“Alvopetro S.A.”). The Merged Entities did not carry on any activities within Brazil or elsewhere and did not hold any assets other than the shares of Alvopetro S.A. held by Alvopetro Investimentos e Participações Ltda.

SUSTAINABILITY OF THE BUSINESS

Alvopetro is committed to having a positive impact on the communities impacted by its operations and on its employees. Since commencing natural gas production in 2020, the Company has been steadily generating cash flows and is committed to ensuring sustainability of the business over the long-term. Sustainability to Alvopetro implies consistent economic returns that enable the Company to pursue its long-term strategy while ensuring adherence to its code of conduct and corporate values.

Alvopetro recognizes the inherent responsibilities in upstream and midstream operations and acknowledges that sustainable economic performance must go hand in hand with environmental stewardship, with due regard for social responsibility including safe operations, and maintaining high standards of corporate governance.

Environmental, Health and Safety Policies and Social Responsibility

Alvopetro's main environmental strategies include the preparation of comprehensive environmental impact assessments and assembling project-specific environmental management plans. Alvopetro encourages local community engagement in environmental planning to create a positive relationship between its business, its stakeholders and those who are impacted by its business.

Alvopetro 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. Monitoring and reporting programs for environment, health and safety ("EH&S") performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Alvopetro maintains an active comprehensive integrity monitoring and management program for all of its production infrastructure including wells, process and storage facilities and associated pipelines. Contingency plans are in place for a timely response to an environmental event and abandonment and remediation and reclamation programs are in place and utilized to restore the environment. Alvopetro has abandoned and reclaimed several wells and sites to date in Brazil, all of which have met the applicable industry and government standards.

Management of Alvopetro are responsible for reviewing Alvopetro's EH&S strategies and policies, including Alvopetro's emergency response plan. Management of Alvopetro reports to the Board on at least a quarterly basis with respect to EH&S matters, including: (i) any incidents and corrective actions taken where applicable; (ii) compliance with all applicable laws, regulations and policies with respect to EH&S; (iii) emerging trends, issues and regulations related to EH&S that are relevant to Alvopetro; (iv) the findings of any significant reports by regulatory agencies, external EH&S consultants or auditors concerning performance in EH&S; (v) any necessary corrective measures taken to address issues and risks with regards to performance in the areas of EH&S that have been identified by management, external auditors or by regulatory agencies; and (vi) the results of any review with management, outside accountants, external consultants and legal advisors of the implications of major corporate undertakings such as the acquisition or expansion of facilities or decommissioning of facilities.

Alvopetro believes that its operations comply in all material respects with applicable environmental laws and is not aware of any proposed environmental legislation or regulations with which it would not be in compliance. However, the oil and gas industry may in the future become subject to more stringent environmental protection rules. This could increase the cost of doing business and have a negative impact on net earnings and cash flows in the future. See "*Risk Factors*" in this AIF for further information.

In 2021, Alvopetro commenced a formal voluntary social contribution program within Brazil targeting the long-term sustainability of seven communities within its direct and indirect areas of influence and completed a comprehensive community assessment visiting over 190 families in its areas of operations. Initiatives in 2025 included:

- a music and arts program benefiting over 1,000 students;
- a program working with over 200 families in rural communities encouraging small plot farming productivity through training in circular water systems and collective cooperation in productive systems and techniques as well as providing health and wellness assistance and guidance to families to promote social well-being; and
- a youth volleyball program offering free volleyball practice and assistance for competitions for over 100 students and young adults.

Environmental Protection

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to various levels of governmental and regulatory bodies and agencies. Environmental regulations set forth numerous prohibitions and requirements with respect to planning and approval processes related to environmental protection including land use, water use, sustainable resource management, waste management, responsibility for the release of presumed hazardous materials, protection of wildlife and flora and fauna, and the health and safety of workers. Legislation provides for restrictions and prohibitions on the transport of dangerous goods and the release or emission of various substances, including substances used and produced in association with certain oil and gas industry operations. The legislation addresses various permits, including for drilling, well completion, installation of surface equipment, air monitoring, surface and ground water monitoring in connection with these activities, waste management and access to remote or environmentally sensitive areas. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of regulatory authorities. Alvopetro's development plans include hydraulic fracture stimulations which are dependent on specific regulatory approvals and future development plans may also require hydraulic fracture stimulations. In addition, certain types of operations may require the submission and approval of environmental impact assessments.

Compliance with environmental obligations and requirements can require significant expenditures and result in delays in the timing of activities. Historically, environmental protection requirements have not had a significant financial or operational effect on the Company's capital expenditures or net earnings. However, environmental legislation and policies are periodically amended and such amendments may result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. Furthermore, there may be additional costs incurred in the future associated with compliance with increasingly complex environmental protection requirements, including with respect to greenhouse gas ("GHG") emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements. This could increase the cost of doing business and may have a negative impact on net earnings in the future. See "*Risk Factors*" in this AIF for further information.

While Alvopetro's long-term strategy in Brazil is focused on increasing natural gas supply overall in Bahia state, Alvopetro recognizes there is an opportunity to minimize its environmental footprint. With respect to pipeline installation, Alvopetro followed existing rights-of-way or used directional boring wherever possible. Alvopetro has also committed to reforestation efforts above and beyond what is required by regulations. To continuously improve efficiency of operations the Company is working with local regulators, both ANP and INEMA (the local environmental regulator in Bahia state), on reporting specific metrics, and will consolidate this information to report on its environmental impact at a corporate level.

Trends in Environmental Regulation

Alvopetro believes that it is reasonably likely the trend towards stricter standards in environmental legislation and regulation will continue. Alvopetro anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities, or otherwise adversely affect Alvopetro's financial condition, capital expenditures, results of operations, competitive position or prospects.

Governance Priorities

Alvopetro has established core values which guide all Company decisions and interacts with a focus on continuous improvement, respect for individuals, communities and cultures, acting in the best interest of shareholders and all stakeholders. Alvopetro's core values are guided by four main principles:

1. Create Value
    - Create long-term per-share growth;
    - Always act as owners;
    - Focus on long-term profitability and recognize the interest of all our stakeholders; and
    - Look for best value when making spending decisions.

2. Build Trust
    - Treat our people and all our stakeholders with respect;
    - Act with honesty and integrity;
    - Be 100% committed to safety;
    - Minimize our environmental footprint; and
    - Meet or exceed regulations using international best practices.

3. Be Accountable
    - Work collaboratively;
    - Share ideas across groups and locations;
    - Objectively measure our performance;
    - Learn from both our successes and failures and celebrate our successes; and
    - Take responsibility and accountability in everything we do.

4. Innovate
   - Take initiative and tackle challenges creatively;
   - Manage risks and find innovative solutions;
   - Challenge ourselves and each other; and
   - Focus on continuous improvement.

The Company's pursuit of its long-term strategy is governed by a firm commitment to business ethics. Alvopetro has established a code of conduct which applies to all employees, officers and directors and sets out the Company's core values and requirements for compliance with respect to various policies of the Company. Topics addressed in the code of conduct include matters concerning anti-corruption, confidentiality, conflicts of interest, insider trading, business conduct and ethics, whistleblower reporting and the Company's human rights policy which is also included by reference in the Company's code of conduct. Alvopetro's human rights policy is guided by the International Bill of Human Rights, the United Nations Guiding Principles on Business and Human Rights, the OECD Guidelines for Multinational Enterprise and the International Labour Organization Declaration on Fundamental Principles and Rights at Work. All employees, officers, and directors are required to certify annually that they understand the code of conduct (including the human rights policy) and provide confirmation of compliance, along with confirmation that any non-compliance has been reported appropriately as provided for under the code of conduct and related policies. A copy of the code of conduct and the human rights policy is available on the Company's website at www.alvopetro.com.

PRINCIPAL PROPERTIES

As at December 31, 2025, Alvopetro held properties in both Brazil and Canada. All of Alvopetro's properties in Brazil are located in the Recôncavo basin onshore Brazil including interests in the Caburé and Murucututu natural gas assets, one exploration block (the western portion of Block 183), comprising 14,748 acres (net). In Canada, Alvopetro held a 50% non-operated working interest in 75 sections of land (23,539 net acres) as of December 31, 2025 focused on the Mannville Stack heavy oil play fairway in Western Saskatchewan. As of the date of this AIF, Alvopetro's land position in Saskatchewan has increased to a 50% interest in 80.5 sections of land (25,760 net acres)

As of December 31, 2025, Alvopetro also held a 100% working interest in the Bom Lugar and Mãe-da-lua oil fields (2,671 acres, gross and net). During 2025, Alvopetro entered into an assignment agreement to dispose of its interests in both. The closing of the sale is subject to standard regulatory approvals, including approval by the ANP.

BRAZIL

The Recôncavo Basin is a 11,500 square kilometre onshore basin, centred 85 kilometres north of the City of Salvador in northeast Brazil, in the State of Bahia. Oil production in Brazil first began in the Recôncavo Basin in 1939. 7,000 wells have been drilled in the Basin, with cumulative production to date exceeding 1.8 billion barrels of oil and 3.0 trillion cubic feet (500 million boe) of natural gas. Basin-wide production is reported to be over 37,000 boe/d, with over 20,600 bopd day of oil and approximately 101 MMcfpd of natural gas. The majority of the basin's production comes from the Sergi, Agua Grande, Candeias and Marfim Formations.

Natural Gas Assets

Caburé Natural Gas Field:

Alvopetro discovered its Caburé gas field with the 197(2) well, drilled in 2014 and tested in 2015. The 197(2) well was previously part of Block 197, awarded in the 9th Brazil Bid Round. Alvopetro filed a declaration of commerciality for the 197(2) natural gas discovery commencing the Development and Production Phase, which extends to December 5, 2043, and "ring-fenced" the gas discovery from the remainder of Block 197. In early 2017, Alvopetro drilled and tested the 198(A1) well on Block 198, a 12th Brazil Bid Round Block, which is adjacent to the Caburé field and forms part of this gas discovery. Alvopetro filed a declaration of commerciality with respect to this well and this portion of the field was named Caburé Leste. The Caburé Leste field is also in the Development and Production Phase with an expiry date of May 12, 2044. The remaining acreage of Block 198 was relinquished to the ANP in May 2017. The Caburé and Caburé Leste Fields are collectively referred to as the Caburé field or Caburé natural gas field throughout this AIF and comprise 4,814 acres.

The Caburé natural gas field extends across the two blocks held by Alvopetro (Block 197 & Block 198 as discussed above) and two adjacent blocks owned by a third party (Blocks 211 and 212). Under Brazilian legislation, petroleum accumulations straddling two or more licensed blocks must undergo unitization (pooling) in order to promote efficient and fair exploration and development. In April 2018, Alvopetro and the third-party partner (the "Partner") finalized the terms of the Unit Operating Agreement ("UOA"), the unit development plan and all related agreements, with Alvopetro's initial share of the Unit being 49.1% and the Partner being named initial operator. Under the terms of the UOA, each party is entitled to nominate for its working interest share of Unit field production and for any natural gas not nominated by the other party. Each party receives 100% of the revenues associated with their natural gas nominations/deliveries representing a portion of that party's share of the recoverable hydrocarbon volumes of the Unit, defined as the estimated ultimate recovery of all hydrocarbons from the Unit ("Unit Recoverable Volumes") on a best estimate basis. Once a party produces its share of Unit Recoverable Volumes, it will no longer be entitled to further gas production allocations. Natural gas liquids production from the Unit is split based on working interest for the entire life of the field.

Effective June 1, 2024, Alvopetro's working interest in the Unit was increased to 56.2% following completion of the first redetermination of working interests. Operatorship of the Unit transitioned to Alvopetro in the third quarter of 2024. Alvopetro's working interest as of December 31, 2025, December 31, 2024 and the date of this AIF is 56.2%. The findings of the first redetermination are currently under dispute and the matter is being reviewed by an arbitral tribunal pursuant to the Rules of Arbitration of the ICC. As of the date of this AIF, the outcome of the arbitration is uncertain and may have a material adverse effect on Alvopetro. For further analysis on the potential impact of the arbitration, refer to the sections entitled *Risk Factors – Arbitration of Alvopetro's Working Interest and Legal Proceedings and Regulatory Actions.*

Costs incurred to date on the Caburé field include drilling and testing Alvopetro's original wells on this field, Alvopetro's share of joint upstream unit development costs including four wells which were drilled in 2025, costs associated with Alvopetro's midstream infrastructure as part of its gas commercialization strategy (including construction of the transfer pipeline and natural gas processing infrastructure, discussed in further detail below, as well as field facility upgrades for compression of natural gas), along with historical costs for bid round bonuses and seismic work.

Murucututu Natural Gas Field:

Alvopetro's Murucututu natural gas field is 6,988 acres (gross and net) extending across Blocks 183 and 197, both held 100% by Alvopetro. As of December 31, 2025, there are four wells at the field including the 183(1) and the 197(1) wells, both of which were drilled in 2014, the 183-A3 well, which was drilled in 2023 and recompleted in 2024, as well as the 183-D4 well which was drilled and completed in 2025. All four wells are tied into field production facilities and a 9-kilometre transfer pipeline connects the field to the Caburé transfer pipeline.

Block 183 is a 9th Brazil Bid Round Block and was acquired through a farm-in agreement signed in May 2013. Alvopetro drilled one well, the 183(1) well, on this block in October 2014 and conducted an initial test on the well in 2018. In 2019, Alvopetro completed the stimulation and initial production test of the 183(1) well and in late 2020 installed a plunger lift system to recover remaining fluids from the stimulation and undertake another production test, which was completed in 2021. In 2021, Alvopetro declared commerciality on this portion of the block, renaming it to Murucututu, and it is now in the Development and Production Phase with an expiry date of April 18, 2048. The remainder of Block 183 is in the second exploration phase as discussed in "*Exploration Assets*" below. In 2021 and 2022, Alvopetro completed the construction of field production facilities and installation of a 9-kilometre transfer pipeline to tie the 183(1) well into the Caburé transfer pipeline. In October 2022, production commenced from the 183(1) well. In 2024 Alvopetro recompleted the 183(1) well; however, based on results, contacted a zone only producing water. The Company recompleted the well in early 2026 and, as of the date of this AIF, is working to bring the well back online. In 2023 Alvopetro drilled the 183-A3 well and testing of the well was completed in January 2024. In the third quarter of 2024, Alvopetro recompleted the 183-A3 well and it commenced production in September 2024. In 2025, Alvopetro drilled and completed the 183-D4 well and the well commenced production in August 2025.

A portion of Block 197 is now part of the Caburé natural gas field as discussed above. The remainder of the block is attributable to the Murucututu natural gas field and costs to date include drilling and testing the 197(1) well, as well as historical costs for 5.9 km^2 of 3D seismic, 122.3 km of 2D seismic, and prior acquisition costs including bid round bonuses. In 2021, the Company declared commerciality on this portion of the block, merging it with Murucututu in the Development and Production Phase with an expiry date of April 18, 2048. In 2023 Alvopetro completed the stimulation of the 197(1) well and it commenced production in the second quarter of 2023. In 2024, the Company completed a chemical injection program on the 197(1) well.

Commercialization:

Alvopetro signed the gas treatment agreement ("Gas Treatment Agreement") with Enerflex in September 2018. Under the terms of the Gas Treatment Agreement, Enerflex constructed and owns and operates a natural gas processing facility (the

"Facility") for Alvopetro and provides all operations and maintenance of the Facility, warrantying the original construction schedule and on-going performance of the Facility. Services from Enerflex commenced in July 2020, upon commencement of natural gas deliveries. In addition to the Facility, Alvopetro constructed an 11-kilometre pipeline from the Caburé Unit to the Facility. In 2022, the operational capacity of the Facility was increased to 500,000 m^3/d (17.7 MMcfpd) under the terms of the existing Gas Treatment Agreement, with capacity above the operational capacity of 500,000 m^3/d (17.7 MMcfpd) made available on a best-efforts basis. In 2026, Alvopetro entered into an expansion agreement with Enerflex to further increase the processing capacity to 600,000 m3/d (21.2 MMcfpd) and to improve the ability to process richer gas from the Murucututu field. The additional capacity is expected to be made available in the third quarter of 2026.

In May 2018, Alvopetro entered into the GSA with Bahiagás. Natural gas deliveries under the GSA commenced July 5, 2020. For all natural gas sales to December 31, 2024, the natural gas price received according to the GSA was set semi-annually (in February and August) using a trailing weighted average basket of benchmark prices including US Henry Hub and UK National Balancing Point gas prices and Brent crude oil prices, incorporating both a floor and ceiling prices adjusted based on United States inflation. The natural gas price is then converted to a Brazilian real ("R$") denominated natural gas price based on a historical average foreign exchange rate and is billed at that R$ denominated price until the next price reset. In December 2024 Alvopetro and Bahiagás agreed to amend the GSA effective January 1, 2025. Under the terms of the amendment, the natural gas price is now set quarterly based on US Henry Hub and Brent oil equivalent prices and the contractual floor and ceiling provisions have been removed. The natural gas price in effect as of January 2026 was R$1.81/$m^3$, increasing to R$1.85/m^3 effective February 1, 2026. Natural gas sales above the firm contracted volumes of 400,000 m^3/d are being sold on a flexible basis at discounts to the firm contracted price.

All natural gas liquids (condensate) production from the Caburé and Murucututu natural gas fields and the Facility is sold pursuant to contracts typically based on premiums to Brent pricing.

Total natural gas sales volumes averaged 13.5 MMcfpd in 2025 (2024 – 10.2 MMcfpd), with 10.5 MMcfpd from the Caburé natural gas field (2024 – 9.2 MMcfpd) and 3.1 MMcfpd from the Murucututu natural gas field (2024 – 0.9 MMcfpd) and natural gas liquids (condensate) sales of 149 bopd (2024 – 90 bopd).

Oil Fields

As of December 31, 2025 the Company held two oil fields (Bom Lugar and Mãe-da-lua). Total oil sales from these two fields averaged 11 bopd in 2025 (2024 – 12 bopd). The Bom Lugar oil field (2,240 gross and net acres), consists of two producing wells, one shut-in well and one active water disposal (injector) well. The field has a production battery equipped with testing, water separation and trucking facilities. In 2023, the Company drilled and completed the BL-06 well, with production from the well commencing in the fourth quarter of 2023. The Mãe-da-lua field (431 gross and net acres) has one producing well and a production battery which is equipped with testing, water separation and trucking facilities.

In the third quarter of 2025, Alvopetro entered into an assignment agreement to dispose of its interests in both fields for total consideration of $0.6 million, including deferred consideration. The closing of the sale is subject to standard regulatory approvals, including approval by the ANP.

Exploration Assets (Block 183)

A portion of Block 183 is part of Alvopetro's Murucututu natural gas field, as discussed above. The western portion of Block 183 comprising 2,946 acres is an exploration asset and includes the 183-B1 well which was drilled in 2022. In Q4 2024, Alvopetro re-entered the existing wellbore with a plan to sidetrack the well. Operational challenges, including loss of the bottom hole assembly prevented the project from continuing and the Company now plans to abandon the well. The Company has identified an additional prospect on the block which is expected to be drilled in advance of the newly extended expiry date of October 1, 2027.

CANADA

In 2025 Alvopetro entered into the Farmin with a private company in Canada which included an agreement to fund 100% of two earning wells in exchange for a 50% non-operated working interest in 12,243 acres of land in Western Saskatchewan. The two earning wells were drilled, completed and equipped in the first quarter of 2025 and sales commenced in mid-April. In the third quarter of 2025, an additional two (1.0 net) wells were drilled, completed and equipped and sales commenced in September 2025.

In October 2025, Alvopetro entered into the Expanded AMI, with Alvopetro agreeing to fund 100% of the costs for drilling two additional earning wells in exchange for a 50% working interest in an additional 47 sections of land (15,010 net acres). These two additional earning wells were drilled in the fourth quarter of 2025 and a seismic program was also completed in the fourth quarter. A further two shared wells (1.0 net) were drilled in early 2026. As of the date of this AIF, there are seven wells (3.5 net) on production and one well (0.5 net) requires remediation. Alvopetro now holds a 50% interest in 80.5 sections of land (25,760 net acres). Total oil sales from the Saskatchewan properties averaged 106 bopd in 2025.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with NI 51-101, Alvopetro engaged GLJ to prepare the GLJ Reserves and Resources Report. The GLJ Reserves and Resources Report included an evaluation of all reserves of Alvopetro as at December 31, 2025. The GLJ Reserves and Resources Report is dated February 25, 2026 with an effective date of December 31, 2025. The GLJ Reserves and Resources Report also included an evaluation of the Corporation's Murucututu natural gas resources as of December 31, 2025, including contingent and prospective resources. For further details on the contingent and prospective resources evaluated as of December 31, 2025, see Schedule B - Disclosure of Contingent and Prospective Resource Data Effective December 31, 2025.

The GLJ Reserves and Resources Report incorporates Alvopetro's working interest share of remaining recoverable reserves held by Alvopetro in both Brazil and Canada. The GLJ Reserves and Resources Report was an evaluation of all reserves of Alvopetro in Brazil and Canada. In Brazil, this includes our working interest share as of December 31, 2025 of the Unit which includes our Caburé and Caburé Leste natural gas fields (collectively referred to as "Caburé" or the "Caburé natural gas field"), our Murucututu natural gas field, as well as our Bom Lugar and Mãe-da-lua oil fields. Alvopetro has entered into an assignment agreement to dispose of its interest in the Bom Lugar and Mãe-da-lua oil fields, subject to regulatory approvals, and these properties are referenced below as "Oil Fields Held for Sale". In Canada, the GLJ Reserves and Resources Report includes our 50% working interest in reserves focused on the Mannville Stack heavy oil play fairway in Saskatchewan.

With respect to Murucututu, Bom Lugar, and Mãe-da-lua, Alvopetro's working interest share as of December 31, 2025 is 100%. With respect to the Unit, which includes the Caburé natural gas field and two fields held by Alvopetro's third-party partner in the Unit, Alvopetro's working interest share as of December 31, 2025 was 56.2%, with the remaining 43.8% held by our partner. For further information regarding Alvopetro's working interest share in Caburé, refer to the section entitled "*Risk Factors – Arbitration of Alvopetro's Working Interest*". With respect to all Canadian properties, Alvopetro's working interest share is 50%.

The tables below are a summary of the reserves attributable to the properties of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Reserves and Resources Report based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Reserves and Resources Report and, as a result, may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, well abandonment and reclamation costs for only those wells assigned reserves and material dedicated gathering systems and facilities. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The GLJ Reserves and Resources Report is based on certain factual data supplied by the Corporation and GLJ's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to GLJ. GLJ accepted this data as presented and neither title searches nor field inspections were conducted.

Summary of Oil and Gas Reserves – Forecast Prices and Costs(1) (2),(3)

By Product

	Light & Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)
Proved										
Producing	1	1	147	127	14,501	13,532	206	192	2,771	2,576
Developed Non-Producing	153	142	0	0	847	790	6	6	301	279
Undeveloped	0	0	192	175	25,464	23,744	547	510	4,983	4,642
Total Proved	**155**	**143**	**338**	**302**	**40,813**	**38,067**	**759**	**708**	**8,054**	**7,497**
Probable	319	297	396	355	23,584	21,948	412	384	5,059	4,693
Total Proved plus Probable	**474**	**440**	**735**	**657**	**64,396**	**60,015**	**1,171**	**1,091**	**13,112**	**12,191**
Possible	242	224	245	207	26,058	24,241	473	439	5,302	4,910
Total Proved plus Probable plus Possible	**715**	**664**	**980**	**864**	**90,455**	**84,256**	**1,644**	**1,531**	**18,415**	**17,101**

By Country

	Canada Properties		Brazil Properties		Total Company	
	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net
	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)
Proved						
Producing	147	127	2,624	2,449	2,771	2,576
Developed Non-Producing	-	-	301	279	301	279
Undeveloped	192	175	4,791	4,467	4,983	4,642
Total Proved	**338**	**302**	**7,716**	**7,195**	**8,054**	**7,497**
Probable	396	355	4,662	4,338	5,059	4,693
Total Proved plus Probable	**735**	**657**	**12,378**	**11,533**	**13,112**	**12,191**
Possible	245	207	5,057	4,704	5,302	4,910
Total Proved plus Probable plus Possible	**980**	**864**	**17,435**	**16,237**	**18,415**	**17,101**

Company Gross	**Total Proved**	**Total Proved plus Probable**	**Total Proved plus Probable plus Possible**
	(Mboe)	(Mboe)	(Mboe)
Caburé Natural Gas Field	1,709	3,036	4,180
Murucututu Natural Gas Field	5,851	8,868	12,540
Oil Fields held for sale	155	474	715
Brazilian Properties, Total	7,716	12,378	17,435
Canadian Properties, Total	338	735	980
Total Company Reserves (Gross)	**8,054**	**13,112**	**18,415**

Summary of Before Tax Net Present Value of Future Net Revenue – Forecast Prices and Costs (1), (2), (3), (4)

By Reserves Category

$000s	Undiscounted	5%	10%	15%	20%
Proved					
Producing	132,223	121,817	113,054	105,655	99,349
Developed Non-Producing	12,784	10,177	8,289	6,884	5,811
Undeveloped	262,861	174,452	124,251	92,940	71,928
Total Proved	**407,868**	**306,446**	**245,593**	**205,479**	**177,088**
Probable	325,814	207,110	148,001	113,193	90,209
Total Proved plus Probable	**733,683**	**513,556**	**393,595**	**318,671**	**267,297**
Possible	417,741	209,615	133,857	96,087	73,274
Total Proved plus Probable plus Possible	**1,151,423**	**723,171**	**527,452**	**414,758**	**340,571**

By Country

$000s	Undiscounted	5%	10%	15%
Proved				
Caburé Natural Gas Field	87,185	81,897	77,243	73,124
Murucututu Natural Gas Field	311,245	216,568	161,584	126,571
Oil Fields Held for Sale	3,861	3,380	2,926	2,533
Brazilian Properties, Total	402,291	301,844	241,752	202,228
Canadian Properties Total	5,577	4,602	3,841	3,250
Total Proved	**407,868**	**306,446**	**245,593**	**205,479**
Proved Plus Probable				
Caburé Natural Gas Field	167,698	149,551	134,501	121,957
Murucututu Natural Gas Field	537,937	343,665	243,916	185,080
Oil Fields Held for Sale	13,434	9,114	6,324	4,483
Brazilian Properties, Total	719,070	502,330	384,741	311,519
Canadian Properties Total	14,612	11,226	8,854	7,152
Total Proved Plus Probable	**733,683**	**513,556**	**393,595**	**318,671**
Proved Plus Probable Plus Possible				
Caburé Natural Gas Field	241,655	205,404	177,338	155,260
Murucututu Natural Gas Field	862,157	485,416	326,634	241,604
Oil Fields Held for Sale	25,596	16,105	10,941	7,866
Brazilian Properties, Total	1,129,409	706,924	514,912	404,730
Canadian Properties Total	22,015	16,247	12,539	10,028
Total Proved Plus Probable Plus Possible	**1,151,423**	**723,171**	**527,452**	**414,758**

Summary of After Tax Net Present Value of Future Net Revenue – Forecast Prices and Costs (1), (2), (3), (4)

$000s	Undiscounted	5%	10%	15%	20%
Proved					
Producing	120,760	111,928	104,347	97,862	92,280
Developed Non-Producing	10,149	8,187	6,730	5,628	4,779
Undeveloped	196,564	130,968	93,385	69,814	53,937
Total Proved	**327,473**	**251,083**	**204,462**	**173,305**	**150,996**
Probable	233,945	150,318	107,956	82,663	65,784
Total Proved plus Probable	**561,418**	**401,401**	**312,418**	**255,968**	**216,780**
Possible	279,996	140,506	89,619	64,227	48,872
Total Proved plus Probable plus Possible	**841,412**	**541,907**	**402,037**	**320,195**	**265,651**

Notes:

(1) The tables above are a summary of the reserves of Alvopetro and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Reserves and Resources Report based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Reserves and Resources Report and as a result may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

(2) Company Gross reserves means the total working interest share of remaining recoverable reserves owned by Alvopetro before deductions of royalties payable to others and without including any royalty interests owned by Alvopetro. With respect to the Caburé natural gas field, Alvopetro's working interest was 56.2% as of December 31, 2025. Refer to the section entitled "*Risk Factors – Arbitration of Alvopetro's Working Interest*" for additional information.

(3) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(4) The net present value of future net revenue attributable to Alvopetro's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties and production taxes, production costs, development costs, other income, future capital expenditures, well abandonment and reclamation costs for only those wells assigned reserves and material dedicated gathering systems and facilities. The net present values of future net revenue attributable to the Alvopetro's reserves estimated by GLJ do not represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

Net Present Value of Future Net Revenue by Product Type – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes(3) (Discounted at 10% per year)		
By Product Type	**$000s**	**$/boe**	**$/Mcfe**
Proved Developed Producing			
Light and Medium Crude Oil(1)	(485)	(386.22)	(64.37)
Heavy Oil(1)	2,582	20.30	3.38
Conventional Natural Gas(2)	110,956	45.34	7.56
Total Proved Developed Producing	**113,054**	**40.80**	**6.80**
Total Proved			
Light and Medium Crude Oil(1)	2,925	20.46	3.41
Heavy Oil(1)	3,841	12.72	2.12
Conventional Natural Gas(2)	238,827	33.87	5.64
Total Proved	**245,593**	**30.49**	**5.08**
Total Proved Plus Probable			
Light and Medium Crude Oil(1)	6,324	14.38	2.40
Heavy Oil(1)	8,854	13.47	2.25
Conventional Natural Gas(2)	378,417	34.11	5.69
Total Proved Plus Probable	**393,595**	**30.02**	**5.00**
Total Proved Plus Probable Plus Possible			
Light and Medium Crude Oil(1)	10,941	16.48	2.75
Heavy Oil(1)	12,539	14.52	2.42
Conventional Natural Gas(2)	503,972	32.36	5.39
Total Proved Plus Probable Plus Possible	**527,452**	**28.64**	**4.77**

(1) Includes solution gas and other by-products.

(2) Including by-products but excluding solution gas.

(3) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

Summary of Before Tax Net Present Value of Future Net Revenue on a Unit Basis – Forecast Prices and Costs

Unit Value[1], Before tax, discounted at 10%/year	$/boe	$/Mcfe
Proved		
Developed Producing	40.80	6.80
Developed Non-Producing	27.57	4.60
Undeveloped	24.94	4.16
Total Proved	**30.49**	**5.08**
Probable	29.26	4.88
Total Proved plus Probable	**30.02**	**5.00**
Possible	25.25	4.21
Total Proved plus Probable plus Possible	**28.64**	**4.77**

(1) Unit values are based on Company Net Reserves.

Total Future Net Revenue (Undiscounted) – Forecast Prices and Costs

($000s)	Revenue	Royalties	Operating Costs	Capital Develop-ment Costs	Abandon-ment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
Proved								
Developed Producing	181,550	12,765	30,701	1,209	4,652	132,223	11,464	120,760
Developed Non-Producing	20,869	1,498	3,881	2,421	284	12,784	2,635	10,149
Undeveloped	398,648	27,296	34,790	71,884	1,817	262,861	66,297	196,564
Total Proved	**601,067**	**41,558**	**69,373**	**75,514**	**6,754**	**407,868**	**80,395**	**327,473**
Probable	413,895	29,975	40,120	16,366	1,620	325,814	91,869	233,945
Total Proved plus Probable	**1,014,962**	**71,533**	**109,494**	**91,879**	**8,374**	**733,683**	**172,265**	**561,418**
Possible	502,070	36,691	46,181	-	1,457	417,741	137,744	279,996
Total Proved plus Probable plus Possible	**1,517,033**	**108,225**	**155,675**	**91,879**	**9,830**	**1,151,423**	**310,009**	**841,412**

Pricing Assumptions – Forecast Prices and Costs

GLJ employed the following pricing and inflation rate assumptions as of December 31, 2025 in the GLJ Reserves and Resources Report in estimating reserves data using forecast prices and costs.

		Brazilian Properties			Canadian Properties
Year	Inflation %	Brent Blend Crude Oil FOB North Sea ($/Bbl)	NYMEX Henry Hub Near Month Contract ($/MMBtu)	Alvopetro-Bahiagas Gas Contract $/MMBtu[1]	WCS Crude Oil (C$/bbl)
2026	0.0	63.25	3.98	8.65	63.08
2027	2.0	70.00	4.00	8.72	69.57
2028	2.0	74.08	4.16	9.98	75.68
2029	2.0	76.32	4.25	10.19	78.01
2030	2.0	77.84	4.33	10.27	79.57
2031	2.0	79.41	4.42	10.48	81.17
2032	2.0	81.00	4.50	10.69	82.79
2033	2.0	82.61	4.60	10.90	84.44
2034	2.0	84.26	4.69	11.12	86.13
2035	2.0	85.95	4.78	11.34	87.86
2036+[2]	2.0/year	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

(1) *Net of sales taxes expected to apply*
(2) *Escalated at a rate of 2.0% per year thereafter.*

With respect to the Company's natural gas reserves, GLJ utilized price forecasts for Brent and Henry Hub to forecast the natural gas price under Alvopetro's GSA. GLJ's oil price forecast in effect on January 1, 2026 for Brent crude formed the basis for the prices used in its evaluation of the Corporation's oil and natural gas liquids reserves in Brazil. In Canada, GLJ utilized price forecasts for Western Canada Select ("WCS") for the prices used in its evaluations of the Corporation's oil reserves in Canada.

In 2025, Alvopetro's realized natural gas price was $9.30/MMBtu ($10.49/Mcf), the realized natural gas liquids price was $73.75/Bbl and the realized oil price was $59.33/Bbl in Brazil and $47.83/Bbl in Canada. Realized prices are net of applicable sales taxes. Pricing realized by Alvopetro for natural gas liquids is typically at a premium to Brent crude while pricing realized by Alvopetro on oil within Brazil is at a discount to Brent. In Canada, pricing realized by Alvopetro on oil is at a discount to WCS.

Reconciliation of Changes in Reserves

The following tables summarize the changes in Gross Reserves from December 31, 2024 to December 31, 2025, by product type and in aggregate (in thousands of barrels of oil equivalent), based on forecast price and cost assumptions. The extensions primarily relate to additional Caruaçu reserves in the Murucututu field following production results from the 183-D4 well which commenced production in 2025, partially offset by technical revisions on the 183-A3 well and adjustments to the Caburé volumetric assessment. Extensions also include newly added reserves from the Canadian properties.

By Product Type:

Light and Medium Crude	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Possible (Mbbl)**	**Proved plus Probable plus Possible (Mbbl)**
December 31, 2024	**150**	**313**	**463**	**235**	**699**
Discoveries	-	-	-	-	-
Extensions and improved recovery	-	-	-	-	-
Technical Revisions	8	6	14	6	21
Acquisitions	-	-	-	-	-
Dispositions	-	-	-	-	-
Economic Factors	-	-	-	-	-
Production	(4)	-	(4)	-	(4)
December 31, 2025	**155**	**319**	**474**	**242**	**715**

Heavy Crude	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Possible (Mbbl)**	**Proved plus Probable plus Possible (Mbbl)**
December 31, 2024	**-**	**-**	**-**	**-**	**-**
Discoveries	-	-	-	-	-
Extensions and improved recovery	338	396	735	245	980
Technical Revisions	39	-	39	-	39
Acquisitions	-	-	-	-	-
Dispositions	-	-	-	-	-
Economic Factors	-	-	-	-	-
Production	(39)	-	(39)	-	(39)
December 31, 2025	**338**	**396**	**735**	**245**	**980**

Conventional Natural Gas	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Possible (MMcf)**	**Proved plus Probable plus Possible (MMcf)**
December 31, 2024	**24,113**	**23,934**	**48,047**	**22,302**	**70,349**
Discoveries	-	-	-	-	-
Extensions and improved recovery	19,314	5,994	25,308	7,187	32,495
Technical Revisions	2,330	(6,343)	(4,014)	(3,431)	(7,444)
Acquisitions	-	-	-	-	-
Dispositions	-	-	-	-	-
Economic Factors	-	-	-	-	-
Production	(4,945)	-	(4,945)	-	(4,945)
December 31, 2025	**40,813**	**23,584**	**64,396**	**26,058**	**90,455**

Natural Gas Liquids	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Possible (Mbbl)**	**Proved plus Probable plus Possible (Mbbl)**
December 31, 2024	**343**	**333**	**677**	**328**	**1,004**
Discoveries	-	-	-	-	-
Extensions and improved recovery	416	129	546	155	701
Technical Revisions	53	(50)	3	(10)	(7)
Acquisitions	-	-	-	-	-
Dispositions	-	-	-	-	-
Economic Factors	-	-	-	-	-
Production	(54)	-	(54)	-	(54)
December 31, 2025	**759**	**412**	**1,171**	**473**	**1,644**

Total, all Product Types (Mboe)

Total, all products (Mboe)	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**	**Possible (Mboe)**	**Proved plus Probable plus Possible (Mboe)**
December 31, 2024	**4,512**	**4,635**	**9,148**	**4,280**	**13,428**
Discoveries	-	-	-	-	-
Extensions and improved recovery	3,974	1,525	5,498	1,598	7,096
Technical Revisions	489	(1,101)	(613)	(575)	(1,188)
Acquisitions	-	-	-	-	-
Dispositions	-	-	-	-	-
Economic Factors	-	-	-	-	-
Production	(921)	-	(921)	-	(921)
December 31, 2025	**8,054**	**5,059**	**13,112**	**5,302**	**18,415**

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the Company’s Gross Reserves for proved undeveloped reserves and probable undeveloped reserves, each by product type, attributed to the Company’s assets:

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Proved Undeveloped										
2023	-	-	-	-	-	2,951	-	54	-	546
2024	-	-	-	-	6,914	7,843	126	143	1,279	1,451
2025	-	-	192	192	19,314	25,464	416	547	3,827	4,983
Probable Undeveloped										
2023	-	221	-	-	7,551	21,405	139	395	1,398	4,183
2024	-	230	-	-	-	11,375	-	208	-	2,334
2025	-	231	340	340	5,994	14,268	129	308	1,468	3,257

The Corporation’s probable undeveloped light and medium oil reserves are primarily attributable to a drilling location on the Bom Lugar field. The Corporation’s proved and probable undeveloped heavy oil reserves relate to Canada and include four (2.0 net) wells in the proved category and an additional four wells (2.0 net) in the probable category. The Corporation’s proved and probable undeveloped natural gas reserves and natural gas liquids reserves at December 31, 2025 are attributable to the Murucututu natural gas project. The proved undeveloped reserves associated with this project relate to six drilling locations targeting the Caruaçu Formation and one well targeting the Gomo The probable undeveloped reserves associated with Murucututu include an additional well targeting both the Caruaçu and Gomo Formations.

A number of factors could result in a delay or cancellation of the Company’s development plans, including changing economic conditions due to natural gas and oil price fluctuations, financial capability of the Company and other risk factors as described within this AIF.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change or additional data becomes available, reserve estimates can change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential process based on information available at that time. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the GLJ Reserves and Resources Report of future net revenue attributable to proved reserves, proved plus probable reserves and proved plus probable plus possible reserves (using forecast prices and costs).

Company Total

	Forecast Prices and Costs			
$000s(1), Undiscounted	Proved Producing	Proved	Proved Plus Probable	Proved Plus Probable Plus Possible
2026	1,209	19,985	19,985	19,985
2027	-	18,361	26,731	26,731
2028	-	24,458	32,454	32,454
2029	-	8,115	8,115	8,115
2030	-	4,595	4,595	4,595
Remaining Years	-	-	-	-
Total Undiscounted	**1,209**	**75,514**	**91,879**	**91,879**

(1) Based on forecast prices and costs.

By Field

$000s(1), Undiscounted	2026	2027	2028	2029	2030	Remaining	Total
Proved							
Caburé Natural Gas Field	1,209	-	-	-	-	-	1,209
Murucututu Gas Field	17,940	15,626	23,907	8,115	4,595	-	70,183
Oil Fields held for sale	-	500	551	-	-	-	1,051
Brazilian Properties, Total	19,149	16,126	24,458	8,115	4,595	-	72,443
Canadian Properties, Total	836	2,235	-	-	-	-	3,071
Total Proved	**19,985**	**18,361**	**24,458**	**8,115**	**4,595**	**-**	**75,514**
Proved Plus Probable							
Caburé Natural Gas Field	1,209	-	-	-	-	-	1,209
Murucututu Gas Field	17,940	15,626	31,903	8,115	4,595	-	78,179
Oil Fields held for sale	-	5,967	551	-	-	-	6,518
Brazilian Properties, Total	19,149	21,593	32,454	8,115	4,595	-	85,906
Canadian Properties, Total	836	5,138	-	-	-	-	5,974
Total Proved Plus Probable	**19,985**	**26,731**	**32,454**	**8,115**	**4,595**	**-**	**91,879**
Proved Plus Probable Plus Possible							
Caburé Natural Gas Field	1,209	-	-	-	-	-	1,209
Murucututu Gas Field	17,940	15,626	31,903	8,115	4,595	-	78,179
Oil fields held for sale	-	5,967	551	-	-	-	6,518
Brazilian Properties, Total	19,149	21,593	32,454	8,115	4,595	-	85,906
Canadian Properties, Total	836	5,138	-	-	-	-	5,974
Total Proved Plus Probable Plus Possible	**19,985**	**26,731**	**32,454**	**8,115**	**4,595**	**-**	**91,879**

(1) Based on forecast prices and costs.

The future development costs for the Caburé field include Alvopetro's working interest share (56.2%) for side-tracking one unfinished well from 2025.

The future development costs for the Murucututu field in the proved category include the recompletion of one (1.0 net) well in the Gomo Formation and the drilling and completion of six (6.0 net) new wells targeting the Caruaçu Formation and one well targeting the Gomo Formation. Also included in the proved category are costs associated with upgrading the Murucututu field production facility and pipeline capacity to increase the overall field capacity from 150,000 m^3/d up to 600,000 m^3/d. The probable category includes two additional development wells, one (1.0 net) targeting the Gomo Formation and one (1.0 net) targeting the Caruaçu Formation.

The future development costs for the Bom Lugar and Mãe-da-lua fields (currently held for sale) in the proved category include costs to stimulate the BL-06 well on the Bom Lugar field and the existing well at the Mãe-da-lua field. Costs in the probable category also include one (1.0 net) development well and costs for a facilities upgrade at the Bom Lugar field.

The future development costs in Canada in the proved category include Alvopetro’s share of costs to drill four (2.0 net) additional wells, one (0.5 net) of which was completed in January 2026. The probable category includes an additional four (2.0 net) wells.

In 2025 the Company entered into the 2025 Loan, with the full balance of $20 million outstanding as of December 31, 2025. The Company expects that all future development costs in each reserve category above, as well as work commitments and other capital plans on its exploration blocks, can be funded primarily from cash flows from the Caburé and Murucututu natural gas fields. However, additional financing may be required for these projects to the extent future revenues are less than anticipated. Financing alternatives include project financing, vendor financing, strategic partnerships, debt issuances or equity issuances. The Company may also explore asset sales or farmouts to assist with funding. The cost of the debt component for funding future development costs is expected to be minimal and to not materially impact the disclosed reserves or future net revenue.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table summarizes Alvopetro’s gross and net wells as at December 31, 2025, which are shut-in or are producing, or which Alvopetro considers to be capable of production, and all of which are located onshore:

	Gross		**Net**	
	Producing	**Non-Producing**	**Producing**	**Non-Producing**
Brazil				
Oil	3	1	3.0	1.0
Gas	13	2	8.6	1.6
Canada				
Oil	6	-	3.0	-
Total	22	3	14.6	2.6

Properties with no Attributed Reserves

As of December 31, 2025, Alvopetro held 2,946 (gross and net) acres of unproved properties with no attributed reserves or production in Brazil, related to the portion of Block 183 that is not part of the Murucututu natural gas field. The Company has identified a prospect on the block which is expected to be drilled in advance of the expiry date of October 1, 2027. To the extent the company executes additional projects, the expiry date may be further extended. See “*Risk Factors – Minimum Work Commitments and Work Plans*” in this AIF for additional details.

For a description of Alvopetro’s prospective resources and contingent resources, see Schedules B and C to this Annual Information Form and also “*Risk Factors*” in this Annual Information Form.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated costs used to calculate total future net revenue from proved plus probable reserves in the GLJ Reserves and Resources Report include abandonment and reclamation costs associated with existing and future wells with reserves assigned and material, dedicated gathering systems and facilities required to enable production of these wells. The estimated abandonment and reclamation costs (with respect to wells and facilities included in the GLJ Reserves and Resources Report) used to calculate total future net revenue from proved plus probable reserves is $8.4 million undiscounted, with all expected costs to be incurred in 2036 or later. The GLJ Reserves and Resources Report does not include abandonment and reclamation costs for existing wells and facilities with no assigned reserves which are included and set forth in the financial statements of Alvopetro. See Note 11 of the Company’s audited consolidated financial statements as at December 31, 2025 for further information.

Costs Incurred

The following table summarizes capital expenditures including capitalized general and administrative expenses related to Alvopetro’s activities for the year ended December 31, 2025:

	Capital Expenditures ($000s)
Property Acquisition Costs	
Proved Properties	-
Unproved Properties	-
Exploration Costs	3,384
Development Costs	30,109
Total	**33,493**

Exploration and Development Activities

Exploration costs in 2025 include final costs for the attempted re-entry and sidetrack of the 183-B1 well on Block 183 which commenced in 2024 as well as long-lead equipment inventory purchases associated with future capital projects. Development costs in the year included projects on the Murucututu and Caburé natural gas fields in Brazil as well as costs incurred on the newly added Canadian properties. On Murucututu, 2025 projects included drilling and completing the 183-D4 well which came on production in late August and recompletion of the 183-A3 well. On the Caburé natural gas field, capital expenditures in 2025 included Alvopetro's share of unit development costs to drill, complete and tie in three (1.7 net) new wells as well as costs to drill a fourth well (0.6 net) which did not reach targeted depth and is expected to be sidetracked in 2026. In Canada, six (3.0 net) wells were drilled during 2025. The following table summarizes the gross and net exploration and development wells we participated in during the year ended December 31, 2025.

	Development wells		**Exploration Wells**		**Total Wells**	
	Gross	Net	Gross	Net	Gross	Net
Brazil						
Oil wells	-	-	-	-	-	-
Natural gas wells	5.0	3.2	-	-	5.0	3.2
Service wells	-	-	-	-	-	-
Stratigraphic test	-	-	-	-	-	-
Dry holes	-	-	1.0	1.0	1.0	1.0
Canada						
Oil wells	6.0	3.0	-	-	6.0	3.0
Natural gas wells	-	-	-	-	-	-
Service wells	-	-	-	-	-	-
Stratigraphic test	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	**11.0**	**6.2**	**1.0**	**1.0**	12.0	7.2

Production Estimates

The following table discloses, for each product type, the average daily production estimated in the GLJ Reserves and Resources Report in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above for 2026.

	Light & Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Conventional Natural Gas (Mcfpd)	Natural Gas Liquids (bbl/d)	Oil Equivalent (boepd)
Proved Developed Producing					
Caburé	-	-	11,653	100	2,043
Murucututu	-	-	3,687	78	693
Other Properties	4	-	-	-	4
Total Brazil	4	-	15,340	179	2,739
Total Canada	-	**130**	-	-	130
Total: Proved Developed Producing	**4**	**130**	**15,340**	**179**	**2,869**
Proved Developed Non-Producing					
Caburé	-	-	-	-	-
Murucututu	-	-	337	2	59
Other Properties	25	-	-	-	25
Total Brazil	25	-	337	2	83
Total Canada	-	-	-	-	-
Total: Proved Developed Non-Producing	**25**	**-**	**337**	**2**	**83**
Proved Undeveloped					
Caburé	-	-	-	-	-
Murucututu	-	-	2,354	51	443
Other Properties	-	-	-	-	-
Total Brazil	-	-	2,354	51	443
Total Canada	-	39	-	-	39
Total: Proved Undeveloped	**-**	**39**	**2,354**	**51**	**482**
Total Proved					
Caburé	-	-	11,653	100	2,043
Murucututu	-	-	6,379	132	1,195
Other Properties	28	-	-	-	28
Total Brazil	28	-	18,032	232	3,266
Total Canada	-	168	-	-	168
Total: Proved	**28**	**168**	**18,032**	**232**	**3,434**
Total Probable					
Caburé	-	-	-	-	-
Murucututu	-	-	309	7	59
Other Properties	22	-	-	-	22
Total Brazil	22	-	309	7	81
Total Canada	-	19	-	-	19
Total: Probable	**22**	**19**	**309**	**7**	**100**
Total Proved plus Probable					
Caburé	-	-	11,653	100	2,043
Murucututu	-	-	6,688	139	1,253
Other Properties	51	-	-	-	51
Total Brazil	51	-	18,341	239	3,347
Total Canada	-	**187**	-	-	187
Total: Proved Plus Probable	**51**	**187**	**18,341**	**239**	**3,534**

Tax Horizon

The GLJ Reserves and Resources Report estimates that the Corporation will be taxable in Brazil in 2026 and future years which is consistent with the Company's expectations. The GLJ Reserves and Resources Report estimates income tax of $6.0 million and $7.7 million, respectively, in the total proved and total proved plus probable categories in 2026, all of which relates to Brazil. In Canada, the GLJ Reserves and Resources Report estimates the Corporation will be taxable in only the proved plus probable plus possible category, commencing in 2033. Ultimately, future taxability in both Brazil and Canada will depend on future activity levels and may change from that estimated in the GLJ Reserves and Resources Report due to additional capital spending and other additional costs such as general and administrative costs not included in the GLJ Reserves and Resources Report but included in the computation of the Corporation's taxable income. As of December 31, 2025, the Corporation has total tax pools in Brazil of $73.5 million and total tax pools in Canada of $15.5 million.

Forward Contracts

As of December 31, 2025, Alvopetro had no risk management contracts in place to hedge its exposure to commodity price fluctuations.

Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2025, information in respect of production, product prices received, royalties, production expenses and the resulting operating netback.

Average Daily Production Volume, Prices Received, Royalties Paid, Production Costs and Netback –Natural Gas, Light & Medium Crude Oil, Heavy Crude Oil and Natural Gas Liquids (NGLs):

	Three Months Ended			
	Mar. 31, 2025	Jun. 30, 2025	Sept. 30, 2025	Dec. 31, 2025
Total Production Volumes				
Natural gas (Mcf)	1,242,230	1,183,218	1,130,935	1,388,437
NGLs (bbls)	12,128	11,642	13,525	16,912
Light & Medium Crude oil (bbls)	939	279	849	1,793
Heavy Crude oil (bbls)	-	12,567	12,696	13,607
Company total (boe)	220,105	221,691	215,559	263,718
Average Daily Production Volumes				
Natural gas (Mcfpd)	13,803	13,002	12,293	15,092
NGLs (bopd)	135	128	147	184
Light & Medium Crude oil (bbls)	10	3	9	19
Heavy Crude oil (bbls)	-	138	138	148
Company total - boepd	**2,446**	**2,436**	**2,343**	**2,867**
Averaged realized prices[(1)]				
Natural gas ($/Mcf)	10.44	10.62	11.04	9.97
NGLs ($/bbl)	81.05	72.32	74.16	69.18
Light & Medium Crude oil ($/bbl)	64.96	53.76	61.25	56.33
Heavy Crude oil ($/bbl)	-	46.95	49.70	46.89
Company total ($/boe)	**63.67**	**63.20**	**65.76**	**59.75**
Operating netback[(1)] - $000s				
Natural gas, oil and condensate revenues	14,013	14,010	14,175	15,756
Royalties	(1,673)	(659)	(763)	(1,009)
Production expenses	(1,167)	(1,190)	(1,314)	(1,589)
Transportation expenses	-	(31)	(48)	(50)
Operating netback[(1)]	**11,173**	**12,130**	**12,050**	**13,108**
Operating netback per boe[(1)]				
Realized sales price ($/boe) [(1)]	63.67	63.20	65.76	59.75
Royalties ($/boe) [(1)]	(7.60)	(2.97)	(3.54)	(3.83)
Production Expense ($/boe) [(1)]	(5.30)	(5.37)	(6.10)	(6.03)
Transportation Expense ($/boe) [(1)]	-	(0.14)	(0.22)	(0.19)
Operating Netback ($ per boe)[(1)]	**50.77**	**54.72**	**55.90**	**49.70**

(1) See "*Non-GAAP and Other Financial Measures*" in this AIF.

CONTINGENT AND PROSPECTIVE RESOURCES

Alvopetro engaged GLJ to prepare the GLJ Reserves and Resources Report. Supplemental disclosure of the contingent and prospective resources evaluated by GLJ in the GLJ Reserves and Resources Report as of December 31, 2025 is included as Schedule B. The report of management and directors on oil and gas disclosure in Form 51-101F3 is included as Schedule C.

INDUSTRY CONDITIONS

BRAZIL

Brazil, located on the east coast of South America, is a federal republic characterized by its large and growing domestic market, diversified economy and oil industry. Brazil has a population of over 218 million people and is the world's eleventh largest economy with proven oil reserves of approximately 17 billion bbls and proven gas reserves of approximately 17 trillion cubic feet (as of 2024 as reported by the ANP) as a result of exploration success and a regulatory framework that allows for private investment.

Exploration in Brazil began in the 1930s and the first commercial discovery was made in 1939 in the Recôncavo Basin in the State of Bahia. However, production output did not experience substantial growth until the late 1970s when the state oil company, Petróleo Brasileiro SA ("Petrobras"), extended its operations offshore. In the Campos Basin, a series of deep-water discoveries were made in the 1980s and 1990s. The discovery of the "pre-salt" reserves (a group of reservoirs older than the salt layer) in the Santos Basin followed those in the Campos Basin, and have become the focal point of current hydrocarbon development in Brazil. The pre-salt discoveries are credited with being the catalyst for making Brazil an increasingly important oil exporter. However, there are also other opportunities that extend beyond the shallow and deep waters' conventional potential, including the mature coastal basins that have yet to undergo next generation exploration and development methodologies. The onshore basin opportunities include new exploration models for additional trapping opportunities, unconventional or tight oil and gas plays and enhanced recovery methods in existing hydrocarbon pools.

Brazil - Hydrocarbon Law & Concessions Regime

Until 1995, Brazilian oil and gas activities were monopolized by state-owned Petrobras. Constitutional Amendment No. 09 (1995) adjusted this monopoly by allowing that the Brazilian government could contract with state-owned and private companies to conduct many oil and gas activities. Today, state-owned or private company participation in these oil activities is regulated in large part by Federal Law No. 9,478 (1997) (the "Petroleum Law"). Under the "concession" regime regulated by the Petroleum Law, the ANP has conducted 17 bidding rounds and additional open acreage auctions to grant concession contracts ("Concession Contract") for onshore and offshore petroleum exploration and production blocks to concessionaries, and to grant production contracts.

In addition to the existing concession regime, newer Brazilian laws have confirmed a "production sharing contract" to be applied for future licensing of the defined pre-salt area and certain other areas to be deemed strategic by the government.

The primary regulatory agencies charged with regulating oil and gas activities in Brazil are:

(a) the Conselho Nacional de Política Energética, or National Council of Energy Policy, an agency of the Brazilian government, having the main purposes of fostering rational use of Brazil's energy resources, ensuring proper functioning of the national fuels inventories system, reviewing energy matrixes for different regions of Brazil, and establishing guidelines;

(b) the ANP, being the national regulator of the oil, gas and biofuels industries, is generally charged with regulating, contracting and supervising activities related to oil and natural gas, and establishing technical standards for various related activities; and

(c) the Ministério de Minas e Energia, or Ministry of Mines and Energy, a Brazilian government ministry fostering investments in mining and energy related activities funding research and establishing government policies.

In addition to this regulatory framework, environmental regulations are applicable and certain licences and permits are required for the performance of oil and gas activities. Government environmental agencies are responsible for issuing such licences and permits and federal or state rules may apply depending on the activity to be carried out. In Bahia state where

Alvopetro operates, Instituto do Meio Ambiente e Recursos Hídricos (INEMA) oversees all environmental licensing with respect to natural gas and oil activities in the state.

As mentioned above, there are two different regulatory frameworks for the granting of exploration and production rights in Brazil: the concession regime and the production sharing contract regime. The exploration and production rights held by Alvopetro fall under the concession regime. Under the concession regime, oil and gas blocks are awarded by means of bidding rounds or open acreage auctions carried out by the ANP. The ANP has the authority to define which oil and gas blocks shall be tendered and to release general terms and conditions comprised in the tender documents. Such tender documents establish all technical, financial and legal documents and requirements that the would-be concessionaire must present or satisfy in order to be qualified to participate in the bidding round under various categories of participation. The ANP's bid evaluation criteria are signature bonus, minimum exploration program, and local content. Federal, state and local governments are recompensed through “government takes”, which are defined as all payments to be made by a concessionaire as a result of the activities of exploration and production of oil and natural gas. Government takes consist of:

- Signature Bonus: a lump-sum payable in a single instalment upon execution of the concession agreement;
- Royalties: financial compensation to be paid monthly by the concessionaries;
- Special Participation: extraordinary financial compensation payable in the event that high volumes of oil or natural gas are produced or a certain field otherwise enjoys high profitability; and
- Payment for area occupation or retention: consists of a yearly sum to be paid for the occupation or retention of oil prospecting areas. ANP sets the amounts to be paid in the bidding documents and concession agreements, but there are minimum and maximum standards established by law.

There is no restriction on direct or indirect foreign participation in exploration and production rights, provided that the foreign investor incorporates a company under Brazilian law with head office and management in Brazil and complies with all technical, legal and financial requirements established by the ANP. No preference rule is established.

Operations are generally divided into two phases: exploration and production. The exploration phase can be 5 years for mature blocks or 8 years for frontier blocks. The exploration terms are outlined in each bid round instruction and for Alvopetro’s blocks are 5 years, consisting of two phases of three and two years. The minimum exploration program of the first exploration phase is the work program bid to win the block, and for the second phase the minimum work program is typically one exploration well.

In the case of a discovery in the exploration phase, the Company must notify the ANP and, to assess the discovery, submit a “Development Assessment” as part of the Development Assessment Plan (“PAD”) phase that may include a specific request for a long-term production test, if required. Once the assessment is complete, the Company submits a “Final Discovery Assessment Report” and then can declare “Commerciality”. A Development Plan would then need to be submitted to the ANP within 6 months following commercial declaration. Once the ANP has accepted and approved the development plan, the operator is granted the area for production purposes with the remaining land returned to the ANP. The development and production phase is for 27 years after the declaration of commerciality but may be extended if approved by the ANP. At the end of the development and production phase, any required abandonment and reclamation will be carried out and the field will be returned to the ANP.

Brazilian Government Initiatives

The Brazilian government has initiatives in place to encourage investment and ultimately natural gas production in the country, including Incentive and Revitalization Program for Exploration and Production Activities (“Potencializa E&P”) and the Monitoring Committee for the Natural Gas Sector (“CMSGN”).

Potencializa E&P

The Potencializa E&P program includes actions and initiatives to stimulate, on a sustainable basis, the exploration, development and production of oil and natural gas in areas of new exploratory frontiers and fields and accumulations of marginal economic viability, attracting private investment. Initiatives of the program are aimed at:

- encouraging the exploration and production of oil and natural gas;
- promoting exploration and production in areas of new exploratory frontiers;
- adopting measures to increase the production, useful life and recovery factor of mature fields with marginal economic viability;

- encouraging the development of offshore accumulations with marginal economic viability through tie backs with existing units;
- adopting, within the attributions of the Ministry of Mines and Energy, actions that lead to a better synergy between the offer of areas and the environmental licensing process;
- establishing mechanisms to interact with government and sectoral actors to encourage the revitalization of oil and natural gas E&P activities;
- ensuring compliance with environmental standards, operational safety and best practices in oil and natural gas exploration and production activities;
- promoting increase in geological knowledge of the national Sedimentary Basins and the greater use of the potential of unconventional resources;
- proposing improvements to the Permanent Offer System for areas for exploration and production of oil and natural gas;
- encouraging the expansion of the supply chain of national goods and services;
- promoting actions to mitigate greenhouse gas emissions in oil and natural gas exploration and production activities; and
- proposing actions for the use of Social Fund resources for mitigation and adaptation to climate change.

National Gas Sector Monitoring Committee
Its purpose is to provide advice, coordination, monitoring of public policies, formulation of proposals and deliberations for the natural gas sector. Responsibilities of the committee include:

(i) monitoring and assessing the continuity and security of supply, within predetermined timeframes, aiming to meet the demand for natural gas and its derivatives in each region of the country;
(ii) monitoring the progress of works and the forecast for the entry into operation of natural gas projects, including the facilities necessary for supplying consumers;
(iii) monitoring difficulties and obstacles of a technical, environmental, commercial, institutional nature, among others, that affect or may affect the regularity and security of supply and the service to the expansion of the natural gas and its derivatives sector;
(iv) preparing proposals for adjustments, solutions and recommendations for preventive or corrective actions for situations observed in items (i) and (iii), when deemed necessary, forwarding them to the competent department;
(v) monitoring compliance with sectoral provisions set forth in the Federal Constitution, Laws, Decrees, Resolutions of the National Energy Policy Council (CNPE) and other provisions that are directly or indirectly related to the natural gas sector, including, where applicable, the oil, its derivatives and biofuels sectors;
(vi) monitoring the development, impacts and results of regulations issued by the ANP;
(vii) prioritizing the order of implementation of the topics to be regulated by the ANP, aiming to comply with the national energy policy and the sectoral public policy itself, without prejudice to the applicable regulatory procedure;
(viii) monitoring the implementation of the actions necessary to open the gas market;
(ix) proposing additional and complementary measures for opening the natural gas market, forwarding them to the competent departments;
(x) interacting with public and private agents of the natural gas industry to implement the measures established in the sectoral regulations and regulations, monitoring any negotiations between them when necessary; and
(xi) interacting with public and private agents of the natural gas industry to assist the Ministry of Mines and Energy and the ANP in the search for harmonization and regulatory improvement.

Local Content

All concession contracts have local content requirements, which are determined during the bidding process for each block and assessed at end of the expiry phase of each bock. If the committed level of local content is not met, the operator will be penalized. Penalties can be levied based on local content at the project level or at the expenditure level. Companies have to submit local content details as part of a regular quarterly report to the ANP. In 2018, the ANP introduced revised regulations to reduce the local content requirements for all blocks and fields held by Alvopetro to 50%. As at December 31, 2025, the Corporation does not have any local content penalties estimated or accrued.

Brazil – Royalties and Sales Taxes

Royalties are chargeable on natural gas, oil and condensate production. The basic royalty payable under the Petroleum Law is 10%. This rate can be varied to a lower rate at the discretion of the ANP, but cannot be reduced below 5%. Reduced rates have occasionally been set during the initial licensing process. In addition, in 2018, the ANP published new legislation allowing companies to apply to reduce the royalty rate for mature fields to as low as 5% on incremental production, subject to the approval of the ANP. Royalties are computed based on production volumes of the raw natural gas or crude oil produced at either a reference price determined and published by the ANP for each field within Brazil or at the sales price.

All of the Concession Contracts held by Alvopetro were initially subject to a base 10% government royalty, other than the Bom Lugar oil field which is subject to a base 5% royalty. In 2021, the ANP introduced legislation to reduce the government royalty rate for medium and small producers from the rate of 10% to 7.5% and 5.0%, respectively. Alvopetro received approval for the rate reduction applicable to medium producers which reduced the government royalty rate to 7.5% effective May 1, 2022 for the Caburé natural gas field and the Mãe-da-lua oil field and effective April 1, 2023 for the Murucututu natural gas field.

In addition, landowners are entitled to a percentage of the production from their lands, which may vary from 0.5% to 1%, to be defined by the ANP according to the Petroleum Law. All of the Concession Contracts held by Alvopetro are subject to a 1% landowner royalty other than the Bom Lugar oil mature field which is subject to a base 0.5% landowner royalty.

Certain third parties are entitled to a gross-overriding royalty (“GORR”) on the portion of Alvopetro’s natural gas fields that were attributable to Block 197 and on the Mãe-da-lua field. The GORR is 2.5% on revenues from these blocks, less government royalties and taxes on revenue. The computation of the GORR is currently in dispute. For further analysis on the potential impact of the GORR dispute, refer to the section entitled “*Risk Factors – GORR Dispute*”.

Sales taxes are due on all natural gas oil and condensate revenues. All revenues are subject to Assistance Contribution (“COFINS”) and Social Integration Program (“PIS”) paid on revenues at a combined rate of 9.25%. Natural gas revenues are also subject to ICMS, which is levied by states within Brazil on the movement of goods. In Bahia state, where Alvopetro operates, the ICMS rate on natural gas revenues is 12%. Under the terms of Alvopetro’s GSA, the natural gas price paid to Alvopetro is grossed up for all PIS, COFINS and ICMS applicable. Tax credits may reduce the amounts otherwise owing by Alvopetro on PIS, COFINS and ICMS.

In 2023, Brazil approved new legislation to consolidate various sales taxes with an aim to simplify the current system in place and reduce compliance costs. Under the reform, five federal, state and municipal taxes will be merged into a ‘dual’ value-added tax ("VAT") charged on goods, services and rights both at the national and regional levels. Nationally, the new VAT will be called Contribution on Goods and Services and will merge the existing PIS, COFINS as well as federal tax on manufactured goods. For state and municipal taxes, the new VAT will be called Tax on Goods and Services and will merge the existing ICMS as well as municipal tax on services. Transition to the new system is to be phased in by 2033 with no changes in immediate effect in 2026. The reform requires further legislation to be approved by Congress including implementing legislation and regulation.

Special Participation

The special participation, set forth in Item III, Article 45 of Brazil’s Law 9,478 of 1997, constitutes an extraordinary financial compensation owed by concessionaires of exploration and production of crude oil and natural gas, like Alvopetro, in the case of a large volume of production or high earnings, in accordance with the criteria established in this decree, and shall be paid in regard to each field of a determined concession area, from the quarter-year in which the respective start-up production date occurs.

The thresholds and rates set out below apply to onshore blocks in Brazil. Production up to these thresholds is exempt from the special participation. The Special Participation is not forecasted to apply to the future net revenues from any of Alvopetro’s reserves in the GLJ Reserves and Resources Report.

	M^3/Quarter (in equivalent oil cubic metres)	**boe/d**	**Special Participation**
Year 1	450,000	31,450	(RLP – RLP*450/VPF)*SP%
Year 2	350,000	24,461	(RLP – RLP*350/VPF)*SP%
Year 3	250,000	17,472	(RLP – RLP*250/VPF)*SP%
Year 4 and thereafter	150,000	10,483	(RLP – RLP*150/VPF)*SP%

Where:
(1) RLP is Net profit per quarter
(2) VPF is production per quarter, measured in thousands of cubic metres of equivalent oil for each field

(3) SP% is the applicable special participation rate between 10% and 40% depending on the quarterly production volume, increasing at higher levels of production.

The net profit corresponding to each field of a given concession area equals the gross revenue from production from the field deducting the corresponding amount of the royalties, exploration investments, operational costs, depreciation and taxes directly related to the field operations, that have been actually disbursed during the concession agreement term, until it is assessed, and which have been determined according to the ANP rules, all divided by the volume of production produced. For the purposes of the calculations described under this "Special Participation" section, all amounts are computed in R$.

When the net profit of a determined field is negative, it may be offset against the calculation of the special participation owed for that same field, for the following quarters.

In case of fields which extend over two or more concession areas, the assessment of the special participation shall be based on the net profit and the total production volume of the fields.

Brazil - Taxes

The Corporation is under the actual tax regime in Brazil. The statutory tax rate applicable to corporate income is 34%. This is comprised of a basic 15% corporate income tax, plus 10% surtax and 9% social contribution tax. Tax losses may be carried forward indefinitely; however, any utilization of losses in a subsequent taxation year is limited to 30% of the taxable income in that period. In 2021, the Company received approval from tax authorities in Brazil for Supertintendência de Desenvolvimento do Nordeste ("SUDENE"), a regional tax incentive offered in Bahia State. Under the incentive, special deductions reduce the inherent current tax payable on qualifying projects to an effective rate of 15.25% (through a 75% reduction in each of the corporate income tax and surtax rates). The effective rate is a corresponding 15.25% where profits for SUDENE profits align with taxable income under the actual profit regime. The SUDENE incentive applies to natural gas profits Alvopetro earns for a period of ten taxation years, commencing January 1, 2021 and ending December 31, 2030. In 2023, the SUDENE incentive applicable to Alvopetro was expanded to include profits from natural gas liquids (condensate) in addition to natural gas. The Company expects the SUDENE rate to be applicable for its natural gas projects in Brazil up to the initial designed facility capacity of 180,000,000 m^3 per annum (493,150 m^3/d or 17.4 MMcfpd). In the 2025 taxation year, the benefit of the SUDENE incentive reduced current tax expense to $2.8 million after recognition of the SUDENE benefit. The Company expects to be taxable in 2026 and future years.

In 2025, Brazil introduced a new 10% withholding tax on dividends effective January 1, 2026 which may result in additional taxes in the future on any dividends paid by Alvopetro's Brazilian subsidiary to its Canadian parent company. There are also a number of other taxes and social contributions that are levied by federal, state and municipal authorities in Brazil on tangible and intangible investments made in connection with oil and gas projects. The two main forms of such levies are value-added (sales) taxes and import duties. The actual application of these levies is project and location specific.

CANADA

Companies operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government as well as with respect to the pricing and taxation of oil and natural gas and royalties applicable thereto through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Corporation. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The industry conditions set out below outline some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the province of Saskatchewan, where our Canadian assets are located. While these matters do not affect our operations in any manner that is materially different than the manner in which they affect other similarly sized industry participants with similar assets and operations, investors should consider such matters carefully. The industry conditions set out below are not an exhaustive summary of all conditions, policies, projects, legislation, regulations and other matters which may have an impact on the Company.

Pricing and Marketing in Canada of Crude Oil

Pricing and marketing of crude oil in Canada is negotiated by buyers and sellers. Worldwide supply and demand are the primary factors influencing crude oil prices, but regional market and transportation issues also impact prices. The price that a producer ultimately receives is influenced by several factors including the quality of crude oil, prevailing prices of alternative fuels, proximity to markets, availability of transportation, the value of refined products, contract term, weather conditions, and contractual terms of sale.

Exports from Canada

The federal government oversees the development and operation of interprovincial and international pipelines. The Canadian Energy Regulator Act ("CERA") and the Impact Assessment Act ("IAA") require a federal regulatory review and Cabinet approval for new interprovincial and international pipelines before they can proceed. The Canadian Energy Regulator ("CER") regulates the export of crude oil, natural gas, and NGL from Canada through the issuance of short-term orders and long-term export licenses. Exporters are free to negotiate prices and terms with purchases provided the reporting obligations set out in the *National Energy Board Act Part VI (Oil and Gas) Regulation* and that export contracts continue to meet criteria set by the CER and federal regulations.

Transportation Constraints and Market Access

One major constraint to the export of crude oil, NGLs and natural gas is the deficit of transportation capacity to transport production from Western Canada to the U.S. and other international markets. While numerous pipeline projects have been proposed, many face cancellation or delays due to regulatory, legal, economic, and sociopolitical challenges. Increased production and insufficient infrastructure have led to lower commodity prices for producers compared to other markets. Producers negotiate transport with pipeline operators based on availability, which varies by region and affects customer options and pricing. Interprovincial and international pipelines require federal approval under Canadian law, but recent uncertainty in policy and regulation often leads to further delays from local governments, public interest groups, and legal opposition, especially concerning Indigenous rights and environmental reviews. Export pipelines to the U.S. also require multiple governmental approvals, adding to unpredictability.

Land Tenure

Mineral Rights

In Western Canada, the rights to crude oil and natural gas is owned predominantly by the respective provincial governments (i.e. the Crown). Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

In addition to Crown ownership of mineral rights, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

Surface Rights

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. For Crown lands, surface access rights can be obtained directly from the respective provincial government. For private lands, access rights can typically be negotiated with the landowner. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Royalties and Incentives

Each province has legislation and regulations in place that govern Crown royalties, production rates and other matters relevant to the industry. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of hydrocarbon production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests, the terms of which are subject to negotiation.

Occasionally respective governments create incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs, or improve environmental performance.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the oil and gas rights, with the remainder being freehold lands. For the Crown lands royalties and taxes (the "Resource Surcharge") are applicable to revenue generated by corporations focused on oil and gas operations. Crown royalties payable on the production of crude oil and natural as are paid on a well-by-well basis. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Producers of crude oil and natural gas receive royalty invoices from the Government of Saskatchewan on a monthly basis.

In addition to surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and subject to applicable deductions.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. The Government of Saskatchewan has a multi-lateral oil well drilling incentive program effective for wells drilled from April 1, 2024 to March 31, 2028, reducing the Crown royalty rate for qualifying wells to 2.5% for a set volume of production depending on the number of laterals drilled.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first establishing the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced.

Regulatory Authorities and Environmental Regulation

The Canadian oil and gas industry is subject to strict environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. These regulations also require the acquisition of permits or other approvals to conduct drilling and other regulated activities; 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; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; impose specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from drilling and production operations. The regulatory regimes also set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("CO2e")), may impose further requirements on operators and other companies in the oil and gas industry.

Liability Management

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "SK LLR Program"). The SK LLR Program is designed to manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to Saskatchewan's orphan fund established under the *Oil and Gas Conservation Act* (Saskatchewan). The orphan fund carries out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when there is no legally responsible or financially able party to manage abandonment and reclamation liabilities associated with a licensee's wells and facilities. The SK LLR Program also outlines requirements for security deposits and licence transfers, including assessments and other transfer due diligence. The SK LLR Program requires all new licensees to submit a C$10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licensees whose deemed liabilities exceed their deemed assets are required to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities and this data is publicly available. On January 1, 2023, Saskatchewan enacted the Financial Security and Site Closure Regulations, which includes: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The Oil and Gas Conservation Regulations, 2012, also updated in January 2023, provide, among other things, a formula for determining a licensee’s liability rating, eligibility requirements for holding licences, and guidance on when a security deposit may be required by a licensee or in connection with a transfer.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") and is a participant in the Copenhagen Accord, a non-binding agreement created by the UNFCCC that represented a broad political consensus and reinforces commitments to reducing GHG emissions. Canada also signed the Paris Agreement which included a commitment to prevent global temperatures from rising more than 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit any increase to 1.5 degrees Celsius. In 2021, Canada updated its original commitment, joining over 90 other countries in the Global Methane Pledge, which aims to reduce global methane emissions by 30% below 2020 levels by 2030. At the 2023 United Nations Climate Change Conference, Canada reaffirmed its commitment to transition away from fossil fuels, targeting to reduce GHG emissions by 40-45% from 2005 levels by 2030 and a commitment to reaching net zero emissions by 2050 has been legislated.

Several policy measures have been put in place to assist in achieving these targets. In 2022, Canada released its first Emissions Reduction Plan under the Canadian Net-Zero Emissions Accountability Act. It models a pathway to achieving Canada’s 2030 target and includes a 42% reduction in oil and gas sectorial emissions from current levels. The reduction plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress was reviewed in 2023 and 2025 and will be reviewed again in 2027, with additional targets to be developed for 2035 and 2050.

In December 2025, Canada finalized Enhanced Methane Regulations to reduce oil and gas methane emissions. The rules take effect for new facilities January 1, 2028, with full implementation at all sites by 2030. They strive to achieve a 72% reduction in oil and gas methane emissions by 2030 (from 2012 levels). The previous regulations were designed to reduce methane emissions by 40% to 45% by 2025. In November 2024, a draft of the Oil and Gas Sector Emissions Cap Regulations was released.

In November 2025 the Federal government formally announced Canada's new Climate Competitiveness Strategy which aims to attract greater investment and build a strong net-zero economy. The strategy emphasizes a strengthened industrial carbon pricing system underpinned by long-term prices and improved benchmarking. The strategy also promises to provide clarity on greenhouse gas regulations to complement the amended carbon pricing system. These initiatives could impact the regulatory environment of the crude oil, natural gas and NGLs industry., enhanced methane regulations and deployment of carbon capture in the sector.

Canada's GHG regime is enacted pursuant to the *Greenhouse Gas Pollution Pricing Act* (the "GGPPA") which has two parts: the output based pricing system ("OBPS") and a regulatory fuel charge which imposed an initial price of $20/tonne CO2e in 2019. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. The price on carbon is set to increase annually at a rate of $15/tonne of CO2e per year, commencing in 2023 through to 2030. In 2021, The federal government established strengthened minimum national standards for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. In March 2025, the federal government made further amendments to the output based pricing system, aligning the system with the elimination of the federal fuel charge effective April 1, 2025. The future emissions threshold and carbon pricing schedule for industrial emitters under the Federal pricing system has remained unclear and we monitor policy changes that impact our operations. Enacted federal carbon pricing impacts provincial jurisdictions that do not have an equivalent OBPS in place. While Saskatchewan has a provincial plan that was previously determined to meet the federal stringency standards, the government of Saskatchewan announced that it was pausing the industrial carbon tax rate under its OBPS program, effective April 1, 2025. As a result, the federal backstop may now apply in Saskatchewan.

On June 20 2024, Bill C-59 came into force, introducing amendments to the *Competition Act* (Canada) (the "Competition Act"), aimed against "greenwashing". "Greenwashing" generally refers to the practice of conveying false or misleading information about an organization's products or services or operations to suggest that the organization is doing more to protect the environment than it is. These amendments expand the Competition Act's deceptive marketing provisions, requiring businesses making environmental claims to substantiate such statements with "adequate and proper tests" or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. These amendments also provide third parties with a private right of action. In late 2025, Bill C-15, ("Bill C-15"), was introduced in the House of Commons. Among other measures, Bill C-15 implements proposals to amend the greenwashing provisions of the Competition Act. In particular, Bill C-15: (i) removes the requirement that environmental claims about a business or business activity be substantiated in accordance with internationally recognized methodology standards, while retaining a general requirement for adequate and proper substantiation; and (ii) removes the ability for private third-parties to bring cases directly to the Competition Tribunal under the greenwashing provisions governing environmental claims made about the benefits of a business or business activity, while leaving intact private access rights under other misleading advertising provisions, including those applicable to product-level environmental claims. Bill C-15 was passed in the House of Commons on February 26, 2026 and is awaiting Senate approval and royal asset.

The *Building Canada Act* was enacted on June 26, 2025 and is intended to streamline federal review and approval processes for identified "nation-building" projects by providing upfront regulatory certainty and a coordinated, single review process through the Major Projects Office ("MPO"). Projects that are designated as being in the national interest, based on contribution to Canada's resilience, autonomy and security, economic benefits, contribution to Indigenous interests, clean growth and Canada's climate objectives and the likelihood of successful project execution, may receive consolidated approvals and conditions, subject to public notice and consultation requirements. Several environmental organizations and Indigenous groups have initiated challenges to the *Building Canada Act* on the basis of its broad powers to override environmental laws, limit public participation, and undermine constitutionally protected rights. Additionally, Indigenous groups have raised concerns that the projects will be designated without meaningful consultation and true consideration of Indigenous rights.

A change in federal government could lead to a policy shift that could impact the regulatory environment of the crude oil, natural gas and NGLs industry.

Saskatchewan

The Management and Reduction of Greenhouse Gases Act (the "MRGGA") regulates GHG emissions in the province. The MRGGA, which is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018, established a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full on December 18, 2018, establishing the framework of an output-based emissions management framework. In November 2022, the Province of Saskatchewan received confirmation that a provincial plan had been approved to replace the federally imposed carbon tax on industrial emitters effective as of January 1, 2023. The Saskatchewan OBPS was previously determined to meet the federal stringency requirements and during the time the Saskatchewan OBPS was in effect, regulated emitters would receive credit for every tonne of CO2e under their permitted amount. The OBPS program in Saskatchewan also included credits for emitters utilizing CCUS technologies at their facilities. As of April 1, 2025, the Government of Saskatchewan announced they were pausing the industrial carbon tax rate under their OBPS program.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. On January 1, 2019, The Oil and Gas Emissions Management Regulations (the Saskatchewan O&G Emissions Regulations) came into effect, requiring facility licensees exceeding 50,000 tonnes of CO2e annually to submit emissions reduction plans. These regulations aim to cut annual emissions by 40% to 45% by 2025, achieving reductions of 4.5 million tonnes of CO2e emissions by 2025 and 38.2 million tonnes of CO2e emissions by 2030.

On April 10, 2019, Saskatchewan produced its first annual report on climate resilience. The report measured the province's progress on goals set out under Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy. Among the goals was the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

In July of 2024, the Government of Saskatchewan and the federal government entered into an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on December 31, 2029.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* ("ESTMA") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over C$100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Bill S-211, *An Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff* (the "Modern Slavery Act") received royal assent on May 11, 2023 and came into force on January 1, 2024. Pursuant to the Modern Slavery Act, entities that meet certain criteria are required to file public reports annually on the steps they have taken prevent and reduce the use of forced labour and child labour in their supply chains.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples* ("UNDRIP") and the principles set forth therein including the principle to seek free, prior and informed consent may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as UNDRIP are expected to continue to add uncertainty to the ability of entities operating in the Canadian crude oil, natural gas and NGLs industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The federal government continues to encourage Indigenous equity ownership in energy and infrastructure projects, including LNG and pipelines. In 2024, the federal government implemented the Indigenous Loan Guarantee Program to provide greater access to capital for Indigenous groups seeking equity participation in energy, mining, transportation, and trade projects. The funding and scope was expanded in 2025. Under the Building Canada Act the federal government is empowered to designate projects as being in the national interest

RISK FACTORS

An investment in Alvopetro should be considered highly speculative due to the nature of its activities and the stage of its development. Investors should carefully consider the risk factors described below, together with all of the other information contained herein before making an investment decision with respect to the Company's Common Shares. If any of the following risks develop into actual events, its business, financial condition or results of operations could be materially adversely affected, and investors could lose all or a portion of their investment. The risks discussed below are based on certain assumptions which later may prove to be incorrect or incomplete. Investors are encouraged to perform their own research with respect to our business, financial condition and prospects.

The risks and uncertainties described below are those that the Company believes are material; however, Alvopetro's business could also be affected by additional risks and uncertainties not currently known or that are currently deemed immaterial. If any of these risks occur, it could materially harm Alvopetro's business, results of operations, funds flow and Alvopetro's overall financial position. This may impair Alvopetro's ability to complete planned development activities, fulfill commitments and obligations, pay dividends at the current level or at all, and Alvopetro's overall financial condition may be materially and adversely affected which could lead to a decline in the market price of the Common Shares.

Arbitration of Alvopetro's Working Interest

Historically, substantially all of Alvopetro's natural gas and condensate sales have been from the Unit. Alvopetro's current working interest in the Unit as of December 31, 2025 and the date of this AIF is 56.2%; however, under the terms of the UOA, the working interest split is subject to redeterminations which may impact Alvopetro's working interest in the future. The first redetermination commenced in 2023 and the parties engaged an independent expert (the "Expert") to evaluate each party's interpretation of their respective working interests. On April 4, 2024, Alvopetro and the Partner received the Expert's decision wherein the Expert found in favour of Alvopetro, increasing Alvopetro's working interest in the Unit from 49.1% to 56.2%. Alvopetro's Partner filed a notice of dispute with respect to the Expert's decision, seeking to stay the redetermination procedure. Alvopetro subsequently filed a request for emergency arbitration before the ICC seeking to make the Expert decision effective starting on June 1, 2024, as provided for in our UOA. On May 10, 2024, Alvopetro received the final order (the "Order") of the emergency arbitrator wherein the arbitrator found in favour of Alvopetro, making the Expert decision effective June 1, 2024 until such time as the dispute can be reviewed by an arbitral tribunal pursuant to the Rules of Arbitration of the ICC.

At Alvopetro's adjusted working interest of 56.2% the Corporation is now entitled to higher natural gas production and condensate entitlements from the Unit and will be responsible for its share of capital expenditures at this higher working interest. With Alvopetro's redetermined working interest above 50%, Alvopetro was entitled to assume operatorship of the Unit effective June 1, 2024. The transition of operatorship was completed in the third quarter of 2024. While the assumption of operatorship has reduced Alvopetro's reliance on the Partner to ensure Alvopetro's entitlement to production from the Unit, Alvopetro is now responsible for the daily activities of the Unit including adherence to regulatory requirements and all administrative matters. The Company ensures compliance through the employment of qualified personnel within Canada and Brazil to manage all local operations. In addition, Alvopetro and the Partner entered into a comprehensive unitization agreement which governs the responsibilities of the operator and non-operators in a fair and balanced approach. Alvopetro has comprehensive insurance coverage with respect to all operations on the Unit.

The redetermination dispute proceeded to a full arbitration under the Rules of the ICC. As the Order is interim in nature, it shall only apply until such time as the matter is reviewed and decided upon by an arbitral tribunal (the "Tribunal"). The full arbitration process is underway, however the timing and outcome of the full arbitration is uncertain and Alvopetro will be exposed to risks and uncertainties as further described below which may impact future revenues, future cash flows and Alvopetro's reserves and reserve life and such impact may be material. This may also increase Alvopetro's exposure to other risks including operational and liquidity and financing risks. In addition, the overall timeline to conclude this process is uncertain and Alvopetro will be exposed to additional legal and other costs associated with the arbitration. Even where Alvopetro is successful, the proceedings may be time consuming and costly. In addition, the UOA provides for future redeterminations which also may have a material impact to Alvopetro.

Revenues

Under the terms of the UOA, each party is entitled to nominate natural gas deliveries based on their working interest share of Unit production plus any natural gas not nominated by the other party. To the extent Alvopetro's working interest is reduced following the decision of the Tribunal, Alvopetro's entitlement to natural gas production from the Unit will be reduced resulting in lower revenues and cash flows in the future. Alvopetro's GSA has ship-or-pay obligations which may give rise to penalties if Alvopetro is unable to deliver the specified firm volumes under the contract as a result of reduced natural gas allocations from the Unit following the redetermination. The terms of the GSA in effect as of January 1, 2025 allow Alvopetro to adjust such firm volumes on 60 days notice in the event of a reduction in working interest following a redetermination.

NGL production from the Unit is shared by each party according to working interest. Following the Order, Alvopetro is currently entitled to 56.2% of the NGL production from the Unit plus an additional 5% until it has recovered the shortfall of historical NGL production (where Alvopetro received only 49.1% of NGL production). To the extent Alvopetro's working interest is reduced following the decision of the Tribunal, Alvopetro's share of NGL sales from the Unit will be adjusted to this new lower working interest less the additional 5% adjustment, contributing to lower revenues and future cash flows.

Any reduction in revenues from a reduction in Alvopetro's working interest in the Unit may have a material adverse effect on Alvopetro's financial condition, financial performance and funds flow from operations. This may also necessitate a reduction or cancellation of dividends paid on Common Shares. While historically virtually all of the Company's natural gas sales have come from the Caburé field, production from the Company's 100% owned and operated Murucututu natural gas field increased in 2025 representing 23% of total natural gas sales volumes in 2025 and 36% in the fourth quarter of 2025. Additional development is planned to increase production from this field. The Company has proved plus probable reserves in Murucututu of 8.9 MMboe as described in *Statement of Reserves Data and Other Oil and Gas Information* and additional risk best estimated contingent resources and risked best estimate prospective resources of 3.8 MMboe and 12.1 MMboe, respectively, as outlined in Schedule B to this AIF. There can be no assurance, however, that production from Murucututu will be sufficient to offset any reduction in working interest from Caburé following the decision of the Tribunal.

Reserves and Reserve Life

Under the terms of the UOA the parties agreed to an aggregate balance of recoverable hydrocarbon volumes defined as the estimated ultimate recovery of all Unit Recoverable Volumes on a best estimate basis. Under the terms of the UOA, once a party produces their share of Unit Recoverable Volumes, they will no longer be entitled to future production allocations from the Unit. To the extent that Alvopetro's working interest is reduced following the findings of the Tribunal Alvopetro's share of remaining Unit Recoverable Volumes from the Unit will decrease. Once Alvopetro has fully depleted its share of Unit Recoverable Volumes it will no longer be entitled to production allocations from the Unit which may result in a material adverse effect on Alvopetro.

Alvopetro's reserves as of December 31, 2025 as presented in this AIF are determined in accordance with the standards contained in the COGE Handbook and NI 51-101 and are based on Alvopetro's working interest of 56.2% as of December 31, 2025. To the extent Alvopetro's working interest is reduced following a decision of the Tribunal, Alvopetro's reserves may be materially reduced which will increase Alvopetro's liquidity and financing risk which could have a material adverse effect on Alvopetro's business, financial condition, results of operations and prospects, and could result in the delay or indefinite postponement of further exploration, evaluation and development of Alvopetro's properties. This could also result in a reduction or cancellation of dividends. In addition, a decline in the reserve values could result in the carrying value of the asset exceeding the recoverable amount, resulting in an impairment loss. Furthermore, Alvopetro's reserves as determined in accordance with the COGE Handbook and NI 51-101 may differ from Alvopetro's remaining entitlement to Unit Recoverable Volumes agreed by the parties under the provisions of the UOA. Even where Alvopetro is still entitled to Unit Recoverable Volumes as determined by the Unit, Alvopetro's remaining reserves determined in accordance with the COGE Handbook and NI 51-101 may be materially different.

Capital Expenditures

Historical capital expenditures of the Unit were adjusted in 2024 to reflect the revised working interest following the Expert decision and the Order. Alvopetro recognized additional historical capital expenditures of $1.1 million in 2024 following this adjustment. Capital expenditures since June 1, 2024 have been allocated based on Alvopetro's current working interest of 56.2% and any future capital expenditures will be allocated in this manner. The majority of the planned unit development was completed in 2025 with Alvopetro's share being 56.2%. To the extent Alvopetro's working interest decreases following a decision of the Tribunal, Alvopetro will be entitled to a recovery of past costs.

Operatorship

Following the Order, Alvopetro assumed operatorship of the Unit. To the extent Alvopetro's working interest decreases below 50% following a decision of the Tribunal, the Partner may be entitled to assume operatorship. To the extent operatorship transitions to the Partner, Alvopetro may be unable to fully control the activities of the Unit and will be dependent on the

Partner to ensure Alvopetro is able to meet production requirements under the GSA and generate future cash flows. Alvopetro will also be dependent on the Partner, to varying extents, to exercise best practices in terms of safety and employment law. While Alvopetro has entered into a comprehensive unitization agreement which governs the responsibilities of the operator and non-operator in a fair and balanced approach, this may not fully mitigate all risks. In addition, Alvopetro may incur additional costs on transition of operatorship.

Asset Retirement and Abandonment Obligations
Alvopetro's share of future abandonment costs associated with Unit wells and Unit facilities, along with site restoration is based on its working interest share. To the extent a decision of the Tribunal reduces Alvopetro's working interest, Alvopetro's share of such future costs will decrease, resulting in a lower obligation in the future.

Escrow Account
The provisions of the UOA and related agreements require that where one party has reached 60% of its total production entitlement of Unit Recoverable Volumes, the parties shall carry out a calculation to forecast the net present value of future abandonment costs and future capital costs net of future NGL sales. To the extent the forecasted costs exceed the forecasted revenues from NGL sales, once a party reaches 70% of its total production entitlement, it is required to contribute to an escrow account to cover the potential shortfall with a deposit of 33% of the balance due, increasing to 66% once 80% of the production has been reached, and to 100% of the balance owing once 90% of the production has been reached. To the extent the decision of the Tribunal reduces Alvopetro's working interest in the Unit, Alvopetro may be required to fund a portion of the escrow account sooner than previously forecasted which may reduce Alvopetro's available cash and financial resources.

Future Redeterminations
The UOA provides for a second redetermination of working interests which is to occur once 40% of the Unit Recoverable Volumes have been produced. To December 31, 2025 a total of 31% of the estimated Unit Recoverable Volumes have been produced. However, a decision by the Tribunal may alter the determination of Unit Recoverable Volumes and, as such, the percentage of such volumes produced to date. Subsequent redeterminations may also occur where there is a variation in the total Unit Recoverable Volumes as determined by the Unit of at least 5%. Any future changes to Alvopetro's working interest as a result of such future redeterminations may also have a material impact to Alvopetro.

Reservoir Performance

The GLJ Reserves and Resources Report was, and all of Alvopetro's future reserve evaluations are expected to be, prepared in accordance with NI 51-101. There are numerous uncertainties inherent in estimating quantities of reserves and funds flow to be derived therefrom, including many factors that are beyond the control of Alvopetro. The reserves information set forth in this AIF represents estimates only. The reserves from Alvopetro's properties have been independently evaluated by GLJ in the GLJ Reserves and Resources Report. The GLJ Reserves and Resources Report includes a number of inputs based on management's judgment and assumptions with respect to timing and execution of development plans. Additional factors affecting the ultimate recoveries from the evaluated properties include initial production rates, production decline rates, future commodity prices, marketability of production, production costs, royalties and other government levies that may be imposed over the producing life of the reserves. All judgments and assumptions were based on the best information available at the date the relevant evaluations were prepared and all are subject to change, some being beyond the control of Alvopetro. Actual production and funds flow derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based, in part, on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated funds flow to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations. The Company has firm sales commitments under the GSA in the event that actual production volumes are less than anticipated, the Company may be subject to ship-or-pay penalties. With increased firm volumes agreed to as of January 1, 2025, Alvopetro's exposure to such potential penalties has increased. However, while the overall firm contracted volumes have increased compared to 2024 and prior years, the new GSA in effect as of January 1, 2025 has reduced supply failure penalties compared to prior years.

Under IFRS, impairment testing is performed at the cash generating unit level, with asset carrying values being compared to the recoverable amount which is the higher of the value-in-use and fair value less costs of disposal. Value-in-use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. When the asset carrying value (including goodwill) is more than the recoverable amount an impairment loss is recorded. A decline in the proved and probable reserve values of the oil and natural gas properties could result in the carrying value of the assets exceeding the recoverable amount, resulting in an impairment loss.

Exploration and Development Activities and Reserve Acquisition and Replacement

The exploration for, and production of, hydrocarbons is a highly speculative activity which involves a high degree of risk. The Company's current reserves will decline as reserves are produced unless the Company is able to discover and develop new reserves which involves exploration and development risk. The long-term commercial success of Alvopetro depends on its ability to find, acquire, develop and commercially produce hydrocarbon reserves. There can be no assurance that Alvopetro's future exploration activities will result in material additions to reserves or that such activities will lead to future cash flows.

The exploration and development of hydrocarbons involve a number of uncertainties that even thorough evaluation, experience and knowledge of the industry cannot eliminate. Alvopetro's exploration and possible development activities in Alvopetro's properties will depend in part on the evaluation of data obtained through geophysical testing and geological analysis. The results of such studies and tests are often subject to varying interpretations and no assurance can be given that such activities will produce hydrocarbons in commercial quantities.. Alvopetro's properties may fail to produce hydrocarbons in commercial quantities.

This Annual Information Form includes estimates of the volumes of the Corporation's prospective resources and contingent resources. The resource estimates from GLJ are estimates only. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent resources. The uncertainty in estimating prospective resources is even greater. There is no certainty that any portion of the prospective resources will be discovered and even if discovered, there is no certainty that it will be commercially viable to produce any portion. With respect to the Corporation's contingent resources, there is uncertainty that it will be commercially viable to produce any portion of the resources. In addition, in respect of contingent and prospective resources, this Annual Information Form includes estimates of the net present value of the future net revenue associated with the contingent resources and prospective resources. Actual results may vary significantly from these estimates and such variances could be material. In addition, there are contingencies that prevent contingent resources from being classified as reserves. Estimates of prospective and contingent resources involve additional risks beyond estimates of reserves. The accuracy of any resources estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resources presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

It is impossible to guarantee that the exploration and exploitation programs on Alvopetro's properties will generate economically recoverable reserves. The commercial viability of a new hydrocarbon pool is dependent upon a number of factors which are inherent to reserves, such as hydrocarbon composition, associated non-hydrocarbon fluids and proximity and availability of infrastructure, as well as commodity prices which are subject to considerable volatility, regulatory issues such as price regulation, taxes, royalties, land tax, import and export regulations, and environmental protection issues. The individual impact generated by these factors cannot be predicted with any certainty but, when combined, may result in non-economical reserves. Alvopetro will remain subject to normal risks inherent to the oil and gas industry such as unusual and unexpected geological changes in the parameters and variables of the petroleum system and operations.

Commodity Price Fluctuations

Commodity prices are unstable and are subject to wide fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. Commodity prices are primarily determined by international supply and demand. Factors which affect commodity prices include, but are not limited to, expectations regarding global supply and demand, government regulations, actions of Organization of Petroleum Exporting Countries and other oil and gas exporting countries, the condition of the Canadian, United States, European and Asian economies, the impacts of geopolitical events, including the Russian Ukrainian war, geopolitical developments in Venezuela and conflicts and hostilities in the Middle East, the imposition of tariffs or other adverse economic or political development in the United States, Europe, the Middle East, Africa, South America or Asia, the impact of global conflicts, worldwide pandemics or other events, government regulation, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy.

With the Company's expansion into Canadian activities in 2025, tariffs or other restrictive measures or counter measures affecting trade between Canada and the U.S. may have a material adverse impact on the Corporation's business, financial condition, results of operations and prospects. Limitations on the ability of Western Canadian energy producers to export crude oil, NGLs and natural gas to United States markets and other world markets and the resulting discount that Western Canadian energy producers may receive for their products as compared to the United States and international benchmark commodity prices could negatively impact the Corporation's business, financial condition, results of operations, prospects and the market value of its Common Shares which could prove to be material over time. In addition, Alvopetro's natural gas and NGL revenues in Brazil are linked to international commodity prices and any impact of such trade disputes may result in a reduction in international pricing impacting Alvopetro's revenues and cash flows in Brazil.

Any material decline in prices will result in a reduction of Alvopetro's future revenue and cash flows from operations. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Alvopetro's reserves. Alvopetro might also elect not to produce from certain wells at lower prices. All of these factors could result in a sustained and material decrease in Alvopetro's future net production revenue which would have an adverse effect on the carrying value of the Company's reserves, its borrowing capacity, profitability and cash flows from operations, and may have a material adverse effect on the Company's business, financial condition, results or operations, and its acquisition and development activities.

The Company monitors market conditions and may selectively utilize derivative instruments to reduce exposure to commodity price movements. However, the Company is of the view that it is neither appropriate nor possible to eliminate 100 percent of its exposure to commodity price volatility.

GORR Dispute

Within Brazil, there is a 2.5% GORR on the portion of Alvopetro's fields that were previously Block 197 and Block 182. The computation of the GORR has been in dispute with the GORR holders, specifically on the computation of the sales price used to calculate the GORR on natural gas from Block 197. Pursuant to dispute resolution provisions, the dispute proceeded to arbitration under the Rules of Arbitration of the ICC. In April 2025 Alvopetro received the findings of the arbitral tribunal wherein the tribunal found in favour of the GORR holders requiring Alvopetro to adjust the sales price used in the computation of the GORR.

Alvopetro was required to submit all calculations of the additional GORR owing to the tribunal for review and the parties are currently discussing the respective calculations. Ultimately, the tribunal will issue a final decision on the amount owing. Alvopetro has estimated the additional GORR owing and recognized the associated amount in its audited consolidated financial statements for the year ended December 31, 2025; however the actual calculation will be determined by the tribunal and may be materially different. As a result, the final amount owing is uncertain as of the date of this AIF as it remains subject to the decision of the tribunal and will be subject to any adjustment required by the tribunal. The final amount owing may be different than the amounts recognized by Alvopetro as of December 31, 2025 and such difference may be material. As the GORR award is subject to inflation and interest adjustments, the balance owing will increase over time and, as the timing of reaching a final decision is uncertain, the proceedings may be time consuming and costly. Moreover, the methodology decided upon by the tribunal for the GORR computation will impact future amounts owing for the GORR on future natural gas sales from Block 197 which will impact future cash flows.

Marketability of Production and Economic Dependence

The Company has entered into a long-term GSA with one counterparty. If this gas sales contract were terminated for any reason, Alvopetro may be unable to enter into a relationship with another purchaser for such gas on a timely basis or on similar terms. Even if a new counterparty were identified, additional infrastructure development may be required to enter into a new gas sales contract which may result in additional capital expenditures and delays in future cash flows and any new contract may not be on similar terms to the Company's existing GSA. Alvopetro's results of operations and future cash flows are dependent on its ability to market its gas production and any change to price or volumes under its gas sales contract may impact future earnings. Where demand is reduced for any reason, future earnings may be reduced as Alvopetro does not currently have other gas sales contracts to sell natural gas to any other parties at rates equivalent to that under the GSA. The GSA contains take-or-pay provisions which mitigate some of the risk. Such provisions the GSA require prepayment for gas volumes where demand is below 80% of the firm volumes under the GSA. Any natural gas volumes which are prepaid pursuant to the take-or-pay provisions are recovered through future natural gas deliveries.

The marketability and ultimate commerciality of oil and gas discovered or acquired is affected by numerous factors beyond the control of Alvopetro. These factors include local demand, reservoir characteristics, market fluctuations, the proximity, capacity and price of oil and gas pipelines and processing equipment and government regulation.

2025 Loan

The 2025 imposes certain restrictions on the Company and also contains certain financial covenants with which the Company must comply, namely with respect to the payment of dividends. A breach of any of the terms of the 2025 Loan could result in some or all of the amounts borrowed becoming immediately due and payable, which could adversely affect the Company's financial condition. It is uncertain whether the Company's assets would be sufficient to generate the funds necessary to repay such amounts in the event of an acceleration. As of December 31, 2025 the Company is in compliance with all financial and non-financial covenants. In addition, there are no facts or circumstances which indicate that the Company will not comply with the covenants in twelve months following the date of this AIF.

The Company may not be able to generate enough cash from operations or may not be able refinance the principal amount outstanding pursuant to the 2025 Loan in order to repay the principal. The Company's ability to make payments of principal and interest will depend on its future operating performance and cash flows from operations, which are subject to prevailing economic conditions, prevailing commodity price levels, and financial, competitive, business and other factors, many of which are beyond its control. The Company's cash flow from operations will be in part dedicated to the payment of the principal and interest and no assurance can be given that the Company will be able to repay the 2025 Loan.

Regulatory Risk Relating to Hydraulic Fracturing

The expanded use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny over potential environmental impacts. Alvopetro's future development include plans for hydraulic fracture stimulations which are dependent on necessary regulatory approvals. Delays in obtaining these approvals may result in delays in the Company's operational plans which may impact its business and future cash flows. In addition, Alvopetro anticipates that there will be a trend towards changing and increased regulatory requirements concerning hydraulic fracturing in the future, in Brazil and internationally. Changes to these regulatory requirements may impact Alvopetro's business requiring it to expend additional costs to comply with future regulatory requirements or, in the future, resulting in it being unable to carry out hydraulic fracturing operations, which may lessen the volume of oil and gas that could otherwise be produced which could have a material impact on the Company.

Inflation and Supply Chain Management

Future capital costs and ongoing operating and other costs could escalate as a result of inflation cost pressures, supply limitations and other factors. Uncertainty with respect to international trade disputes and the timing and extent of new and expanded tariffs as well as the duration of any such measures increases the risk of escalating costs to the Company. A failure to secure the services and equipment necessary for the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows. The Company's operating costs could escalate and become uncompetitive due to supply chain delays or disruptions, inflationary cost pressures, equipment availability limitations, escalating supply costs, commodity prices, or new taxes or other regulations. There can be no assurance that sufficient drilling and completion equipment, services and supplies will be available when needed or at the forecasted cost. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows. The cost or availability of equipment and services may adversely affect the Company's ability to undertake exploration and development projects. These materials and services may not be available when required at reasonable prices. Failure to secure the services and equipment necessary to the Company's operations for the expected price on the expected timeline may have an adverse effect on the Company's financial performance and future cash flows. Alvopetro's inability to control rising costs may impact future funds flow from operations and may result in delays in project execution and planned developments, further impacting financial performance. Shortages of available equipment could: (i) delay Alvopetro's exploration, development, and sales activities; (ii) have a material adverse effect on Alvopetro's financial condition; and (iii) cause Alvopetro to not meet the local content requirements of its concession contracts, incurring penalties.

Foreign Currency and Fiscal Matters

Alvopetro is exposed to market risks resulting from fluctuations in foreign exchange rates, particularly with respect to natural gas, crude oil and condensate revenues in Brazil and on cash and cash equivalent balances in Brazil. With respect to revenues, although the revenues in Brazil are linked to USD benchmark prices, actual invoices for such sales are denominated in R$, exposing the Company to foreign currency risk. This is especially significant with respect to natural gas sales under the Company's long-term GSA as the natural gas price is determined quarterly and converted to a fixed R$ denominated price in

m^3 based on historical exchange rates. The Company receives the fixed R$/$m^3$ until the next price determination date. As a result, fluctuations in the actual USD to R$ exchange rate from the average historical rate used to determine the R$ denominated natural gas price will result in USD realized prices which differ from the USD natural gas price at the price determination. Should the R$ depreciate from the average historical rate used in determining the R$ denominated natural gas price, the Company will realize lower equivalent USD until the next price reset which may result in a material decrease in funds flow. With respect to crude oil and condensate revenues, commodity prices received are based on USD benchmark prices on the date of sale, converted to R$ at the foreign exchange rate applicable on that date. In addition, any cash balances retained in Brazil are held in R$ and therefore subject to foreign exchange fluctuations on a USD equivalent basis. A material devaluation of the R$ relative to the USD could result in a material adverse effect on Alvopetro's funds flow, revenues, cash and working capital and overall financial position. The Company is also exposed to foreign exchange rate risk related to C$ from its Western Canadian operations.

In 2025, Brazil introduced a new 10% withholding tax on dividends effective January 1, 2026 which will result in additional taxes in the future on any dividends paid by the Company's Brazilian subsidiary to Canada. While there are no restrictions or taxes owing on any repatriations of capital, the new withholding tax on dividends will result in increased costs to the Company. Changes in foreign exchange regulations, further restrictions on repatriation of funds from Brazil or the imposition of additional income taxes or withholding taxes on repatriations may adversely affect the Company's ability to obtain cash from its Brazil subsidiaries to meet obligations within Canada, including the payment of dividends. The impact on future cash flows may be material. Amendments to current taxation laws and regulations that alter tax rates, benefits, or deductions could have a material adverse impact on Alvopetro.

To the extent that revenues and expenditures denominated in or strongly linked to the USD are not equivalent, Alvopetro is exposed to exchange rate risk. In addition, substantially all expenditures in Brazil are denominated in R$, which are difficult to hedge.

Alvopetro's cash and cash equivalents consists of balances on deposit at banks and short-term deposits and investments maturing in less than 90 days and Alvopetro's restricted cash consists of cash and cash equivalents and short-term deposits maturing in one year or less. Alvopetro is exposed to credit risk related to such deposits and investments. Market uncertainty associated with financial institution instability, bank collapses, international conflicts, geopolitical factors and pandemics increases Alvopetro's exposure. Alvopetro manages this risk by investing only in term deposits or investments of investment grade credit rating.

Legal and Regulatory

As an oil and gas company, Alvopetro is subject to extensive governmental and environmental approvals and regulations. Oil and gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Delays in obtaining regulatory approvals could result in project delays and an inability to meet contractual obligations and commitments. Changes to these regulations could delay timelines and increase the costs of conducting business. Environmental concerns relating to the oil and gas industry's operating practices are in the global spotlight and this may result in more stringent government regulation. Alvopetro is uncertain as to the amount of operating and capital expenses that will be required to comply with enhanced environmental regulation in the future as discussed in further detail in the Risk Factor entitled "*Environmental Regulation*".

In 2024 Bill C-59 came into force, introducing amendments to the *Competition Act* (Canada) (the "Competition Act"), aimed against "greenwashing". "Greenwashing" generally refers to the practice of conveying false or misleading information about an organization's products or services or operations to suggest that the organization is doing more to protect the environment than it is. These amendments expand the Competition Act's deceptive marketing provisions, requiring businesses making environmental claims to substantiate such statements with "adequate and proper tests" or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. These amendments also provide third parties with a private right of action. In late 2025, Bill C-15 was introduced in the House of Commons, which, if enacted, would further amend the greenwashing provisions of the Competition Act, including by modifying substantiation requirements for certain environmental claims and limiting private access rights in respect of business-level environmental claims. See "Industry Conditions – Canada – Climate Change Regulation".

While the Company will take all efforts necessary to comply with these regulations, such laws and regulations may increase our costs and risks associated regulatory compliance and we may be subject to increased litigation, which may have a material adverse effect on the Company. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Corporation's business, financial condition, results of operations and prospects.

It is possible that the Brazil or Canadian government or regulatory authorities could choose to change their respective tax laws, royalty regimes, environmental laws or other laws and reporting requirements applicable to oil and gas companies and that any such changes could materially adversely affect Alvopetro, its shareholders and the market value of the Common Shares.

Alvopetro’s operations may also be adversely affected by laws and policies of Canada affecting foreign trade, taxation and investment. Tariffs, retaliatory tariffs or other counter measures may adversely affect Alvopetro’s operations within Canada as well as in Brazil, depending on the nature of and extent of such measures.

In the event of a dispute arising in connection with Alvopetro’s foreign operations, Alvopetro may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgments in such other jurisdictions. Alvopetro may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, Alvopetro’s exploration, development and production activities in the foreign jurisdictions in which it operates could be substantially affected by factors beyond Alvopetro’s control, any of which could have a material adverse effect on Alvopetro.

Litigation

In the normal course of operations, we have disputes and other legal proceedings, including regulatory proceedings, tax proceedings or other legal actions. Potential litigation may develop in relation to contract disputes, employment matters, personal injuries, property damage, environmental issues and securities law matters. Such litigation claims may be material. While the Company rigorously defends its positions in any such matters, the outcome of any litigation is uncertain and may materially impact the Company’s financial condition. Even where the Company is successful in any dispute or legal proceeding, the proceeding may be time consuming and costly which could also have an adverse effect on the Company.

Reliance on Third Party Operators and Key Personnel

All of Alvopetro’s natural gas is processed through the Facility owned and operated by Enerflex under the terms of the Gas Treatment Agreement. Although Alvopetro has full control over the gas processed within the Facility, Alvopetro does not have full control over the detailed operations of the Facility. From time to time, the Facility may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. While the GSA allows for scheduled downtime and routine maintenance, should such downtime be unplanned or extend for longer than anticipated, this could have a material adverse impact on the Company’s operations and could give rise to ship or pay penalties under the GSA if the Company is unable to meet its firm production requirements. The terms of the Gas Treatment Agreement include strict availability requirements and downtime credits to minimize Alvopetro’s costs associated with reduced processing; however, such credits may not fully offset costs incurred by Alvopetro due to ship or pay obligations under the GSA.

To the extent that Alvopetro is not the operator of its properties, it may be unable to fully control the activities related to its interests. Within Canada, Alvopetro holds a 50% non-operated working interest on properties in Western Saskatchewan. As Alvopetro is not the operator of this property, it is dependent on its partner for the timing and execution of the planned activities and is also dependent on its partner, to varying extents, to exercise best practices in terms of safety, environmental regulations, and employment law. To mitigate these risks, Alvopetro partnered with an established operator with a proven track record operating in Canada and entered into a comprehensive agreement governing the responsibilities of the operator and non-operators in a fair and balanced manner in accordance with standard operating procedures published by the Canadian Association of Petroleum Landmen.

Alvopetro’s success depends, to a significant extent, upon management and key employees. The loss of any key employee could have a negative effect on Alvopetro. Attracting and retaining additional key personnel will assist in the expansion of Alvopetro’s business. Should other oil and gas projects or expansions proceed in the same time frame as Alvopetro’s projects, Alvopetro may compete with these other projects for experienced employees and contractors and such competition may result in increases to compensation paid to such personnel or to a lack of qualified personnel. There is no assurance that Alvopetro will successfully attract and retain personnel required to continue to expand its business and to successfully execute its business strategy.

Dividends

Alvopetro's quarterly dividend payments are not guaranteed and may fluctuate due to results of operations, plans for future development and the overall performance and financial condition of the Company, all of which are impacted by the risk factors described herein. The Board of Directors has full discretion with respect to the declaration, timing, amount and payment of future dividends. Dividends may be reduced or eliminated completely at the discretion of the Board of Directors, which may affect the market price of the Common Shares.

Management of Growth

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

In 2025 Alvopetro announced the entry into Canadian operations with the Farmin, partnering with a private company. Six (3.0 net) wells had been drilled within Canada as of December 31, 2025 with a further two wells (1.0 net) drilled as of the date of this AIF. Alvopetro may make other acquisitions and dispositions of businesses and assets in the ordinary course of business. With respect to the Farmin, while members of the management team and Board of Directors have previous experience operating in Canada, Alvopetro has not previously held oil and gas assets within Canada and entry into a new country increases the Company's exposure to other risks discussed herein, including, but not limited to, marketability of production, commodity price fluctuations, legal and regulatory, reliance on third party operators, management of growth, inflation and supply chain management, income tax, and competition. Achieving the benefits of the Farmin and any future acquisitions and new activities depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Alvopetro's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Alvopetro. The integration of acquired businesses, properties and operations may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Actual operating, technological, strategic and revenue opportunities, if achieved at all, may be less significant than we expect or may take longer to achieve than anticipated. Management expects that noncore assets will be periodically disposed of, so that Alvopetro can focus its efforts and resources more efficiently. Depending on the state of the market for such noncore assets, certain noncore assets of Alvopetro, if disposed of, could realize less than their carrying value on the financial statements of Alvopetro.

In 2025 Alvopetro entered into an assignment agreement to dispose of its interests in the Bom Lugar and Mãe-da-lua oil fields within Brazil for total consideration of $0.6 million, including deferred compensation. The closing of the sale is subject to standard regulatory approvals, including approval by the ANP. There can be no assurance that such approval will be received or even if received, that such approval will be received in a timely manner. Moreover, consideration for the disposition includes deferred compensation payable in the future and actual amounts received may be received later than anticipated, or not at all.

Minimum Work Commitments and Work Plans

From time-to-time Alvopetro must fulfill certain minimum work commitments and other work plans on projects in Brazil. There are no assurances that all of these commitments and work plans will be fulfilled within the time frames allowed. As such, Alvopetro may lose certain exploration or development rights on the blocks affected and may be subject to certain financial penalties that would be levied by the applicable governmental authority. From time to time, it is expected that Alvopetro may request extensions or suspensions to the timeframe allotted for work commitments and work plans and there is no assurance that any such extensions or suspensions will be granted. To the extent requests are not approved, acreage positions may be lost, and fines or penalties may be applied. Block 183, an exploratory block in Brazil, has an expiry date of October 1, 2027. Alvopetro is responsible to drill an additional well on the block in advance of the expiry date and there is no assurance that such future activity will result in any addition to reserves or that such activity will lead to future cash flows.

Price Volatility of Publicly Traded Securities

In recent years, the securities markets in Canada and the United States have experienced a high level of price and volume volatility. The market price of securities of many companies, particularly those considered to be development stage companies, has experienced wide fluctuations in price which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for the Common Shares will be subject to market trends generally, notwithstanding the financial and operational performance of Alvopetro. In addition, Alvopetro's trading volumes have historically been low. All of these factors may impact investor decisions as they may make it difficult for a shareholder to sell Common Shares at a price equal to or above the price at which the shares were purchased.

Liquidity and Financing, Access to Capital and Future Financing Requirements

The Company's ability to make payments of interest and principal on current and future amounts borrowed, ongoing general and administrative costs, and costs for future development will depend on future operating performance and cash flows from operations. If the Company's revenues or reserves decline or are lower than forecasted, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs and may require additional financing to do so.

The future operating performance and cash flows from operations are subject to the risks described in this section including timing of capital activities, regulatory approvals, reservoir performance, prevailing economic conditions and commodity prices, among other factors, many of which are beyond its control. Costs associated with future capital projects may be materially higher than expected. The Company's cash flow from operations in 2026 and 2027 will be in part dedicated to the payment of principal and interest on the 2025 Loan and there can be no assurance that the Company will be able to repay the 2025 Loan and fund all other ongoing operational and administrative expenditures and future development costs without additional financing. The Company may also seek to raise funds in the future to fund future capital expenditures on Alvopetro's properties or other potential business development activities. There can be no assurance that debt or equity financing will be available or sufficient to meet these requirements or, if debt or equity financing is available, that it will be on terms acceptable to Alvopetro. The inability of Alvopetro to access sufficient capital for its planned operations could have a material adverse effect on Alvopetro's business, financial condition, results of operations and prospects, and could result in the delay or indefinite postponement of further exploration, evaluation and development of Alvopetro's properties.

The extent to which Alvopetro will need to access additional funding will be subject to normal capital market risks, primarily the availability and cost of capital. Expectations for the future price of oil and gas will be an important factor in determining Alvopetro's ability to access additional debt financing at the time that this may become necessary. In addition, future changes in interest rates may increase borrowing costs which may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and funds flow. Rising interest rates could also result in a recession which may have a negative impact on demand for oil and natural gas, causing a decrease in commodity prices.

Environmental Regulation

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills and releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Alvopetro to incur costs to remedy such discharge. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Alvopetro's financial condition, results of operations or prospects. In addition, regulations relating to greenhouse gas emissions in Brazil, Canada or elsewhere in the world may have an effect on Alvopetro's costs or on levels of future demand for hydrocarbon-based products.

There has also been considerable focus from investors and potential investors on the impact of oil and gas operations on the environment and communities in which oil and gas companies operate. As a result, certain investors may divest of any interest in oil and gas companies or the industry as a whole. This may further limit Alvopetro's ability to access sources of financing in the future should it be required. Furthermore, even where capital is available, such investors may require the implementation of more stringent policies and practices concerning environmental matters, including with respect to GHG emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements. More stringent policies and monitoring requirements may come at a significant cost and time commitment of management, which may increase the overall cost of capital and have a negative impact on future cash flows from operations and earnings. As further discussed in "*Risk Factors – Legal and Regulatory"*, public statements with respect to ESG matters, including GHG emissions reduction strategies, environmental targets, or, more broadly, ESG-related goals, are becoming increasingly subject to heightened scrutiny from public and governmental authorities with respect to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential ESG benefits and are now subject to greater scrutiny as a result of the enactment of Bill C-59. As a result, the Corporation may face increased litigation risks from private parties and governmental authorities related to its ESG efforts which could, in turn, lead to further negative sentiment and diversion of investments.

In addition to new and stricter standards in environmental legislation, there may be additional costs to comply with sustainability tracking and disclosure standards. Emissions, carbon and other regulations impacting climate and climate related matters are constantly evolving. In 2023 the International Sustainability Standards Board (ISSB) issued two new international sustainability disclosure standards, *IFRS S1 - General Requirements for Disclosure of Sustainability-related Financial Information* and *IFRS S2 - Climate-related Disclosures*, with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. Using these standards as a baseline, the Canadian Sustainability Standards Board has released its own two sustainability disclosure standards modified for the Canadian context, the *Canadian Sustainability Disclosure Standard 1 - General Requirements for Disclosure of Sustainability-related Financial Information* and *Canadian Sustainability Disclosure Standard 2 - Climate-related Disclosures*. In addition, the Canadian Securities Administrators is developing Proposed National Instrument 51-107 – *Disclosure of Climate-related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. The cost to comply with new standards or any other similar disclosure standard has not yet been quantified and may be material to the Corporation. Alvopetro may be adversely affected if it is unable to comply with new standards.

International Operations

Although Brazil has been a favourable host country for Alvopetro's operations to date, changes in government may alter the level of support for oil and gas activities, potentially resulting in revisions to existing oil and gas regulations in Brazil or to tax or other laws that could adversely affect the Corporation. There can be no certainty as to the outcome of any resulting change in regulations or laws within Brazil.

Additional uncertainties that can apply to developing countries include, but are not limited to, changes in energy and environmental policies and the administration of such, social instability, corruption, revolution, border disputes, expropriation or nationalization of assets without fair compensation or marketable compensation, renegotiations or modification of existing contracts, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, limits on allowable levels of production, currency exchange controls, labour disputes and other uncertainties arising out of foreign government sovereignty over Alvopetro's international operations. Alvopetro's operations may also be adversely affected by changes in applicable laws and policies of Brazil, which could have a negative impact on Alvopetro.

The Corporation's international and Canadian operations may also be adversely affected by laws and policies of Canada, including as they pertain to oil and gas development, foreign trade, taxation and investment or political relations with Brazil and imposed economic sanctions.

Income tax and other tax laws affecting the Company may change in the future or be interpreted in a manner that adversely affects the Company. In 2025, Brazil introduced a new 10% withholding tax on dividends effective January 1, 2026 which will result in additional taxes in the future on any dividends paid by our Brazilian subsidiary to Canada. While there are no restrictions or taxes owing on any repatriations of capital, the new withholding tax on dividends will result in increased costs to the Company. Changes in foreign exchange regulations, further restrictions on repatriation of funds from Brazil or the imposition of additional income taxes, withholding or other taxes on repatriations may adversely affect the Company's ability to obtain cash from its Brazil subsidiaries to meet obligations within Canada, including the payment of dividends. The impact on future cash flows may be material.

The majority of Alvopetro's operations are conducted in Portuguese and the Company may enter into significant contracts in Portuguese which may give rise to uncertainties. The Company manages this risk through the employment and involvement of qualified personnel within Brazil in all local operations. The majority of personnel in Brazil belong to a labour union which has defined requirements with respect to compensation and benefits for employees. Although this has not been an issue for Alvopetro, an employee strike could cause disruption of Alvopetro's operations and have an adverse financial impact.

Operating Hazards and Uninsurable Risks

Oil and gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts and oil spills, each of which could result in substantial damage to oil wells, production facilities, other property and the environment or in personal injuries or loss of life. Hazards such as unusual or unexpected geological formations, pressures or other conditions may be encountered in drilling and operating wells. As Alvopetro has interests in a limited number of properties, such risk is more significant than if spread over a greater number of properties. In accordance with industry practice, Alvopetro is not fully insured against all of these risks, nor are all such risks insurable. Although Alvopetro maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Alvopetro could incur significant costs that could have a materially adverse effect upon its financial condition, resulting in a decline in the value of the securities of Alvopetro. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Our insurance policies are generally renewed on an annual basis and, depending on various factors the premiums, policy limits or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Insurance companies may discontinue or reduce insurance coverage to companies operating in the oil and gas sector. Should any insurance companies refuse to continue to provide insurance coverage, our overall risk exposure could be increased. We may be unable to renew existing policies or find replacement policies on reasonable terms or at all and we could incur significant costs.

Cyber Security

The Company is dependent upon the availability, capacity, reliability and security of its information technology infrastructure. In the event the Company is unable to effectively utilize its software and hardware, upgrade systems and network infrastructure as required, and take other steps to maintain or improve the efficiency of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data. Information systems could be interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Given the nature of and the geographical separation of offices and operations, any of these or other events could cause interruptions, delays, loss of critical or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, confidential and proprietary information, and on the Company's business, financial condition, results of operations and cash flows from operations.

The Company is also subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential or proprietary information, interruption to communications or operations or disruption to the Company's business activities or its competitive position. Cyber-attacks and other cyber-related security incidents (such as phishing attempts) have become more widespread and sophisticated in recent years. If the Company becomes a victim of any such attack or incident it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. Although the Company has measures and controls in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information or financial resources could occur and result in a loss of material and confidential information and reputation, breach of privacy, disruption to its business activities and/or a financial loss. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Cybersecurity and data protection laws and regulations continue to evolve and are increasingly demanding which may increase the Corporation's costs of compliance and expose it to reputational damage or litigation, monetary damages, regulatory enforcement actions, or fines.

Income Tax and Other Taxes

The Company and its subsidiaries file all required income tax returns in Canada and Brazil and the Company believes that it is in full compliance with all applicable tax laws. However, all income tax and other tax filings are subject to audit and potential reassessment by applicable taxation authorities. The determination of income and other taxes requires interpretation of complex laws and regulations involving multiple jurisdictions and such determination involves significant judgment. In the event of audit or other reassessment of the Company's income tax or other tax filings, where this is a differing interpretation of laws or regulations and the impact of such laws or regulations on the computation of taxable income or other indirect tax amounts owing, or a differing interpretation with respect to the applicability and computation of any tax benefits or tax credits, such findings may have an impact on current and future income and other indirect taxes payable and such changes may be material.

The Company is subject to extensive indirect taxes within Brazil including sales taxes on natural gas, oil and condensate revenues. With increased revenues in recent years, such sales taxes have also increased. All indirect tax filings are made as required and the Company believes it is also in full compliance with all indirect tax laws.

Tax laws affecting the Company may change in the future and such changes may adversely affect the Company. There can be no certainty as to any changes in tax or other laws and the impact on the Company. Such changes may be material.

Global Conflicts

Global conflicts such as the ongoing Russia and Ukraine war, the conflict in Iran and the Middle East, geopolitical tensions between the United States and Venezuela as well as changes in political regimes or parties in power have led to market uncertainty. Such conflicts can have a significant impact on global commodity prices. The extent and duration of such conflicts and the resulting market disruption is uncertain and could have a negative impact on the global economy for an unknown period of time. Global markets have been experiencing a period of heightened economic uncertainty with more volatile commodity prices and currency exchange rates, as well as inflationary pressure. It is difficult to reliably estimate the length or severity of the financial impact of these events in their entirety and such volatility and disruptions may also magnify the impact of other risks described in this "*Risk Factors*" section.

Corruption

Alvopetro is governed by the laws of many jurisdictions, which prohibit bribery and other forms of corruption and Alvopetro has strict policies and procedures in place that prohibit such activities, requiring all employees and contractors to read the Company's Code of Conduct and related policies and procedures and acknowledge their understanding and compliance on an annual basis. It is possible that Alvopetro, or some of its employees or contractors, could be involved in or charged with bribery or corruption. Brazil has a much higher perceived level of public sector corruption than Canada or the United States, increasing Alvopetro's exposure to this risk. The 2025 published Corruptions Perceptions Index (CPI) score for Brazil was 35/100 compared to 75/100 in Canada and 64/100 in the United States with lower scores attributed to higher levels of perceived public sector corruption. If Alvopetro is found guilty of such a violation, which could include a failure to take effective steps to prevent or address corruption by its employees or contractors, Alvopetro could be subject to onerous penalties. A mere investigation itself could lead to significant corporate disruption, high demand on financial and personnel resources and forced settlements (such as the imposition of an internal monitor). In addition, bribery allegations or bribery or corruption convictions could impair Alvopetro's ability to work with governments or nongovernmental organizations. Such convictions or allegations could result in the formal exclusion of Alvopetro from a country or area, national or international lawsuits, government sanctions or fines, project suspension or delays, reduced market capitalization and increased investor concern.

Competition

The oil and gas industry within Brazil and Canada is highly competitive, both with respect to the acquisition of prospective oil and gas properties and reserves as well as in attracting financing sources for the acquisition of new reserves or the development of existing reserves and marketing production. Alvopetro's competitive position depends on its geoscience and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Alvopetro will compete with a substantial number of other companies having larger technical staff and greater financial and operational resources and access to capital. Many such companies not only engage in the acquisition, exploration, development and production and sale of petroleum reserves, but also carry on refining operations and market refined products. In Brazil particularly, Alvopetro competes with Petrobras and other larger independent oil companies and other industries supplying energy and fuel in the marketing and sale of oil and gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Alvopetro may encounter challenges with respect to transporting and marketing crude oil and natural gas. Access to pipelines and other transportation infrastructure may be limited and/or the terms on which such access is provided may not be favourable to the Company.

Climate Change – Physical Risk

Extreme climate conditions including floods, forest fires, earthquakes, hurricanes, drought and other weather related events may impact Alvopetro's operations or that of its major customers or suppliers. Climate change may increase the frequency and severity of such events and future events may have a material adverse effect on Alvopetro. The Company's financial results for 2025 were not directly impacted by a climate event and the Company did not have any weather related damages to its properties. The Company maintains insurance coverage that provides a level of insurance for certain events that may arise due to climate change factors, however, the Company's insurance program is subject to limits and various restrictions. No claims were made under the Company's insurance policies in 2025 with respect to climate related matters.

Dilution and Further Sales

Alvopetro may issue additional Common Shares or other securities to finance its capital expenditures with respect to its properties, certain of Alvopetro's other capital expenditures, or for other reasons. The constating documents of Alvopetro permit it to issue an unlimited number of additional Common Shares and an unlimited number of Preferred Shares (as defined below) and such future issuances may be dilutive to shareholders.

Permits, Licenses and Leases

Alvopetro's properties and activities on such properties are held in the form of permits, licenses and leases and working interests in permits, licenses and leases. If Alvopetro or the holder of the permit, license or lease fails to meet the specific requirement of a permit, license or lease, the permit, license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each permit, license or lease will be met. The termination or expiration of Alvopetro's permits, licenses or leases or the working interests relating to a permit, license or lease may have a material adverse effect on Alvopetro's results of operations and business.

Furthermore, the development of Alvopetro's properties will require additional permits, licenses, and regulatory approvals. If such permits, licenses, or regulatory approvals are not obtained or if the conditions provided for in such permits, licenses, and regulatory approvals are substantially different from the expectations of Alvopetro, it may have a material adverse effect on Alvopetro's results of operations and business.

Disruptions in Production

Other factors affecting the production and sale of natural gas, oil and condensate that could result in decreases in profitability include: (i) expiration or termination of leases, permits or licences, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labour or community difficulties; (v) maintenance activities; (vi) limitations on access to pipeline capacity; and (vii) changes in the market and general economic conditions. Weather conditions, equipment replacement or repair, fires, and geological conditions can have a significant impact on operating results. In addition, there can be no assurance that labour, community or similar issues will not affect Alvopetro's ability to produce or sell oil and gas in the future.

Non-resident taxation

Shareholders who are non-residents of Canada may be subject to additional taxation. The Tax Act imposes a withholding tax of 25% on dividends paid by the Company to non-residents of Canada unless the rate is reduced under a tax treaty between Canada and the non-resident's country of residence. Such withholding tax rates may change from time to time. Non-resident shareholders are encouraged to consult their own tax advisors for more information concerning additional taxation that may be applicable to them.

Delay in Cash Receipts and Credit Worthiness of Counterparties

Payment by purchasers of natural gas, oil, and natural gas liquids to Alvopetro (and, by an operator to Alvopetro) may be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts, payment fraud or the insolvency or financial impairment of any counterparty owing money to Alvopetro. Delays in collections or the inability to collect amounts owed to Alvopetro could have a material adverse effect on Alvopetro's financial position, liquidity and the ability to meet its financial obligations.

Structure of Alvopetro

From time to time, Alvopetro may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of Alvopetro and its subsidiaries. If the manner in which Alvopetro structures its affairs is successfully challenged by a taxation or other authority, Alvopetro and its Shareholders may be adversely affected.

Risk Management and Hedging Activities

Alvopetro may evaluate the use of and may employ exchange-traded or over-the-counter derivative structures to hedge commodity prices, interest rate and foreign exchange risk. In the past Alvopetro has entered into forward contracts to manage its exposure to fluctuations in the R$ relative to USD. Risks associated with such products include, but are not limited to, counterparty risk, settlement risk, liquidity risk and market risk which could impair or negate Alvopetro's hedging strategy and result in a negative impact on its earnings and funds flow.

Additionally, if oil and gas prices, interest rates or exchange rates increase above or decrease below those levels specified in any future hedging agreements, such hedging arrangements may prevent Alvopetro from realizing the full benefit of such increases or decreases.

Additionally, due to the uncertain worldwide economic environment, there can be no assurance that Alvopetro will be able to engage credit worthy counterparties in hedging activities.

Title Matters

Alvopetro's properties may be subject to unforeseen title claims. While Alvopetro will diligently investigate title to all property and follows usual industry practice in obtaining satisfactory title and, to the best of Alvopetro's knowledge, title to all of Alvopetro's properties are in good standing, this should not be construed as a guarantee of title. Title to Alvopetro's properties may be affected by undisclosed and undetected defects.

Failure to Maintain Listing of the Common Shares

The Common Shares are currently listed for trading on the facilities of the TSXV and also trade on the OTCQX® Best Market, a U.S. market operated by OTC Markets Group. The failure of Alvopetro to meet the applicable listing or other requirements of the TSXV or specific requirements of the OTC in the future may result in the Common Shares ceasing to be listed for trading on the TSXV or ceasing to be traded on the OTCQX, which would have a material adverse effect on the value of the Common Shares. While management makes every effort, there can be no assurance that the Common Shares will continue to be listed for trading on the TSXV or will continue to be eligible for trading on the OTCQX.

Transportation Costs

Disruption in or increased costs of transportation services could make oil and gas a less competitive source of energy or could make Alvopetro's oil and gas less competitive than other sources. The industry depends on pipelines, trucking, ocean-going vessels, and barge transportation to deliver shipments, and transportation costs are a significant component of the total cost of supplying crude oil and natural gas. Disruptions of these transportation services because of weather-related problems, pandemic-related lockdowns, strikes, lockouts, delays, mechanical problems or other events could temporarily impair the ability to supply natural gas and crude oil to customers and may result in lost sales. In addition, increases in transportation costs, or changes in transportation costs for oil and gas produced by competitors, could adversely affect profitability. To the extent such increases are sustained, Alvopetro could experience losses and may decide to discontinue certain operations forcing Alvopetro to incur closure and/or care and maintenance costs, as the case may be. Additionally, lack of access to transportation may hinder production from Alvopetro's business and Alvopetro may be required to use more expensive transportation alternatives.

Pandemic Risk

Alvopetro's business, financial condition or liquidity may be materially and adversely impacted by pandemics, epidemics or outbreaks of an infectious disease in Canada, Brazil or worldwide. The extent to which any pandemic, epidemic or other such infectious disease may impact the Company's operations, financial condition and future financial performance is currently unknown and pandemic risk may increase other risks including: 1) market risk due to volatility in commodity prices as a result of reduced oil and natural gas demand and due to volatility in foreign exchange markets; 2) operational risks due to workforce disruption or shut down orders which may restrict current operations and cash flows or future capital projects; 3) financing risk to the extent additional capital is required as financing alternatives may be limited or only available with terms unacceptable to Alvopetro as a result of reduced commodity prices and continued volatility in the financial markets; and 4) foreign operations risk given the majority of the Company's operations are undertaken in Brazil which, historically was more adversely impacted by pandemics.

Forced Labour

In May 2023 *An Act to Enact the Fighting Against Forced Labour and Child Labour in Supply Chains Act and to Amend the Customs Tariff* was passed and came into force on January 1, 2024. Under this new legislation any company subject to the reporting requirement (including Alvopetro) is required to report annually on measures taken to prevent and reduce the risk that forced labour or child labour is used within its supply chain and to conduct certain due diligence on its supply chains. Alvopetro is currently not aware of any forced or child labour in any of its supply chains; however, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which Alvopetro has a connection and this could negatively impact our reputation. In addition, Alvopetro will be exposed to additional costs in order to comply with these reporting requirements.

Conflicts of Interest

Circumstances may arise where members of the Board of Directors or officers of Alvopetro are directors or officers of companies which compete with Alvopetro. No assurances can be given that opportunities identified by such persons will be provided to Alvopetro. See "*Conflicts of Interest*".

Ineffective Internal Controls

Effective internal controls are necessary for the Company to provide reliable financial reports and to help prevent fraud. Although the Company has implemented a number of procedures in order to help ensure the reliability of its financial reports, including those that may be imposed on the Company under securities laws, the Company cannot be certain that such measures will ensure that the Company will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Company's results of operations or cause the Company to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's consolidated financial statements and may result in a decline in the price of the Common Shares.

Costs of New Technology

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 provide them with technological advantages and may in the future allow them to implement new technologies before the Company does. 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.

Forward-Looking Information May Prove Inaccurate

Shareholders are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves 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 information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading "*Forward-Looking Statements*".

DIVIDENDS AND DISTRIBUTIONS

In 2021 the Corporation established a dividend policy pursuant to which the Company expects to pay a regular quarterly dividend. The implementation of the dividend policy is part of the long-standing objective of the Corporation to provide shareholders with a sustainable return while retaining cash flows within the Corporation to fund reinvestment and development opportunities for future growth. If declared by the Board, quarterly dividends are expected to be payable to shareholders of record on or about the last business day of the month in each quarter of March, June, September and December with such dividends paid on or about the 15th day of the following month. It is intended that dividends declared and paid will qualify as "eligible dividends" for the purposes of the Tax Act. No assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board of Directors.

The amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including, without limitation, results of operations, fluctuations in commodity prices, business performance, foreign exchange rates, production levels, expected capital expenditure requirements, debt and working capital levels, the taxability of Alvopetro, ability to raise capital, and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. There can be no guarantee that Alvopetro will maintain its dividend policy and, even where dividends continue, that such dividends will continue at the current rate.

The following table sets forth the amount of cash dividends declared per Common Share for the periods indicated. The dividend of $0.12 per Common Share declared in the fourth quarter of 2025 included a special dividend of $0.02 per Common Share. All dividends declared and paid are in U.S. dollars. The dividends declared in Q4 are paid in January of the following year.

$ per share	**Q1**	**Q2**	**Q3**	**Q4**	**Annual Total**
2023	0.14	0.14	0.14	0.14	0.56
2024	0.09	0.09	0.09	0.09	0.36
2025	0.10	0.10	0.10	0.12	0.42

On January 3, 2023, Alvopetro announced the approval of the 2023 NCIB under which Alvopetro was authorized to repurchase up to 2,876,414 Common Shares of the Company over the period commencing on January 6, 2023 and ending on the earlier of January 5, 2024 or such earlier date as the NCIB was completed or was terminated at the Company's election. A total of 4,600 Common Shares were repurchased at an average price of C$6.76 per share and were subsequently cancelled. The 2023 NCIB terminated on the expiry date of January 5, 2024.

On August 13, 2024, Alvopetro launched the 2024 NCIB, the terms of which permit Alvopetro to repurchase up to 2,953,044 Common Shares from August 13, 2024 to the earlier of August 12, 2025 or when the 2024 NCIB was completed or terminated by Alvopetro. A total of 340,000 Common Shares were repurchased at an average price of C$5.07 per share and were subsequently cancelled. The 2024 NCIB terminated on August 13, 2025.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote for each Common Share held on all votes taken at meetings of holders of Common Shares. The holders of Common Shares are entitled to receive such dividends as Alvopetro's directors may from time to time declare, subject to the rights of shares having priority over the Common Shares. Subject to certain terms and conditions, Alvopetro may issue Common Shares as payment of all or any portion of dividends declared on the Common Shares for those Shareholders who elect to receive share dividends instead of cash dividends. In the event of the winding up or dissolution of Alvopetro, whether voluntary or involuntary or for the purpose of a reorganization or otherwise or upon any distribution of capital, the holders of Common Shares are entitled to the surplus assets of Alvopetro and generally will be entitled to enjoy all of the rights attaching to shares of Alvopetro, subject to the rights of shares having priority over the Common Shares.

Alvopetro had 36,732,097 Common Shares outstanding as of December 31, 2025 and the date of this AIF.

Preferred Shares

The Corporation is authorized to issue preferred shares ("**Preferred Shares**") in one or more series. The Board of Directors is authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series. Preferred Shares are entitled to a priority over the Common Shares with respect to the payment of dividends and the distribution of assets upon the liquidation, dissolution or winding-up of the Corporation. Alvopetro has no Preferred Shares outstanding as at December 31, 2025.

Bank Debt

On November 28, 2025 the Company entered into the 2025 Loan. The 2025 Loan has a two-year term and bears interest at a fixed rate of 7% per annum (including all applicable charges and fees), payable quarterly. The Loan has a 12-month grace period upon which the loan is to repaid in quarterly instalments commencing on November 30, 2026 and ending on November 29, 2027. The Loan may optionally be repaid at an earlier date but such early repayments would be subject to early payment penalties. As of December 31, 2025 the full balance of $20 million is outstanding.

In connection with the 2025 Loan, the Company's Brazilian subsidiary entered into a standby letter of credit guaranteeing the 2025 Loan and Alvopetro entered into a parent guarantee, guaranteeing the obligations of the Brazilian subsidiary under both the 2025 Loan and the standby letter of credit. The Loan agreement includes standard events of default and acceleration provisions that require early repayment, including, but not limited to, failure to pay amounts owing (advances or interest) when due and payable, failure to comply with covenants, cross-default provisions on other obligations outstanding, invalidity of security registrations, and certain change of control and reorganization transactions as well as significant asset dispositions.

The Loan contains certain financial covenants related to the payment of dividends by Alvopetro. Dividends are permitted to the extent the total amount of dividends declared by Alvopetro in the four fiscal quarters immediately preceding the date of declaration of such dividend, does not exceed the Adjusted Cash Flow from Operations for the same period where Adjusted Cash Flow from Operations is defined as Cash Flow from Operating Activities calculated on a consolidated basis, before changes in non-cash working capital, less the total of all interest accrued during the period and principal payments due under the Loan during the same period; and, on a consolidated basis, Alvopetro maintains a minimum cash or cash equivalents balance of $3.0 million on the closing date of the fiscal quarter immediately preceding the declaration of such dividend. As of December 31, 2025 and the date of this AIF, the Corporation was in compliance with all covenants under the 2025 Loan. A copy of the 2025 Loan is available on the Corporation's SEDAR+ profile at www.sedarplus.ca.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSXV under the trading symbol "ALV" and have traded on such stock exchange since December 5, 2013. On January 15, 2019, Alvopetro's common shares commenced trading on the OTCQX® Best Market, a U.S. market operated by OTC Markets Group (OTCQX: OTCM), under the symbol "ALVOF".

The following table sets forth the reported market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSXV for the year ended December 31, 2025.

Month (2025)	Price Range (C$) High	Low	Total Aggregate Monthly Trading Volume
January	5.38	4.56	606,238
February	5.19	4.71	227,953
March	5.18	4.50	354,494
April	5.41	4.51	308,086
May	6.04	5.17	486,766
June	7.49	5.75	437,384
July	6.28	5.65	297,458
August	6.02	5.67	330,061
September	6.99	5.98	350,416
October	6.90	6.26	249,718
November	6.58	5.93	547,837
December	6.99	5.99	749,571

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with Alvopetro and its subsidiaries and the principal occupations of the persons who serve as directors and executive officers of Alvopetro as of the date hereof are set out below.

Name and Municipality of Residence	Position Held(1)	Position Since	Principal Occupation During the Preceding Five Years
John D. Wright(3)(4) Calgary, Alberta	Chairman	September 25, 2013	President, Analogy Capital Advisors Inc. since March 2017.
Corey C. Ruttan(3) Calgary, Alberta	Director, President and Chief Executive Officer	September 25, 2013	President and Chief Executive Officer of Alvopetro since November 2013. Director of Alvopetro since September 2013.
Kenneth R. McKinnon(2)(4) Calgary, Alberta	Director	November 19, 2013	Independent consultant.
Geir Ytreland(3) *Drobak, Norway*	Director	November 19, 2013	Independent geologist.
Firoz Talakshi(2) Calgary, Alberta	Director	November 19, 2013	Independent director.
Roderick L. Fraser(2)(4) *New York City, NY and Salvador, Brazil*	Director	December 16, 2013	Independent director.
Alison Howard Calgary, Alberta	Chief Financial Officer	November 28, 2013	Chief Financial Officer of Alvopetro since November 2013.
Adrian Audet Calgary, Alberta	Vice President, Asset Management	August 12, 2020	Vice President, Asset Management since August 2020. Prior thereto Operations Director and other operational positions at Alvopetro since November 2013.

Notes:
(1) Each Director will hold office until the next annual meeting of the shareholders of Alvopetro.
(2) Member of the Audit Committee of the Board of Directors.
(3) Member of the Reserves Committee of the Board of Directors.
(4) Member of the Compensation Committee of the Board of Directors.

As of the date hereof, the directors and executive officers of Alvopetro, as a group, beneficially own, directly or indirectly, or exercise control or direction over 3,475,755 Common Shares or 9.5% of the number of Common Shares issued and outstanding as of the date of this AIF.

Corporate Cease Trade Orders

To the knowledge of the management of Alvopetro, no director or executive officer of Alvopetro (nor any personal holding company of any of such persons) is, or within the ten years before the date of this Annual Information Form has been, a director, chief executive officer or chief financial officer of any company (including Alvopetro) that:

(a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, a “Cease Trade Order”) that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to a Cease Trade Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

Mr. John D. Wright was the President and Chief Executive Officer and a director of Lightstream Resources Ltd. (“Lightstream”), and Mr. Corey C. Ruttan and Mr. Kenneth R. McKinnon were directors of Lightstream when it obtained creditor protection under the Companies’ Creditors Arrangement Act (Canada) (“CCAA”) on September 26, 2016. On December 29, 2016, as a result of the CCAA sales process, substantially all of the assets and business of Lightstream were sold to Ridgeback Resources Inc. (“Ridgeback”), a new company owned by former holders of Lightstream’s secured notes. Mr. Ruttan and Mr. McKinnon resigned as directors of Lightstream upon formation of the new company. Mr. Wright resigned as an officer and director of Lightstream and was concurrently appointed President and Chief Executive Officer and a director of Ridgeback upon closing of the sale transaction.

On November 30, 2017, Mr. John D. Wright became a director of OAN Resources Ltd. ("OAN"), a private issuer and on May 17, 2018, Mr. Corey C. Ruttan also became a director of OAN. On June 14, 2019, the management of OAN filed a Notice of Intention to Make a Proposal under subsection 50.4(1) of the Bankruptcy and Insolvency Act to restructure OAN's affairs. Mr. Wright and Mr. Ruttan resigned as directors of OAN on October 10, 2019. OAN was unable to file a proposal within the provided period and was deemed to have made an assignment into bankruptcy on October 13, 2019.

Except as otherwise disclosed herein, to the knowledge of the management of Alvopetro, no director or executive officer of Alvopetro (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Alvopetro to affect materially the control of Alvopetro:

(a) is, at the date of this Annual Information Form or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Alvopetro) that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

Mr. Corey C. Ruttan entered into a settlement agreement with the Alberta Securities Commission on May 3, 2002 in respect of an insider trading violation relating to trade made on May 17, 2000. Mr. Ruttan cooperated completely in resolving the matter with the regulators. The settlement resulted in Mr. Ruttan paying an administrative penalty of $10,000, representing a return of profits, and the costs of the proceeding in the amount of $3,925. For a period of one year, Mr. Ruttan agreed to cease trading in securities and to not act as a director or officer of a public company. These restrictions expired on May 3, 2003. Mr. Ruttan is a Chartered Professional Accountant in good standing.

Except as otherwise disclosed herein, to the knowledge of management of Alvopetro, no director or executive officer of Alvopetro (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Alvopetro to affect materially the control of Alvopetro has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

CONFLICTS OF INTEREST

Certain directors and officers of Alvopetro are associated with other reporting issuers or other corporations which may give rise to conflicts of interest. In accordance with corporate laws, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Alvopetro are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Alvopetro. From time to time, Alvopetro may jointly participate in exploration and development activities with one or more corporations with which a director or officer of Alvopetro may be involved. Some of Alvopetro's directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with Alvopetro. Some of the directors of Alvopetro have either other employment or other business or time restrictions placed on them and accordingly, these directors of Alvopetro will only be able to devote part of their time to the affairs of Alvopetro. In particular, certain of the directors and officers are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, provide financing to, or make equity investments in, competitors of Alvopetro. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. See "*Risk Factors – Conflicts of Interest*".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Alvopetro is not a party to any legal proceeding nor was it a party, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2025, nor is Alvopetro aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of Alvopetro except as described below.

In connection with the first redetermination of working interests in the Unit, Alvopetro's 100% wholly-owned subsidiary, Alvopetro S.A., and the Partner in the Unit appointed the Expert to redetermine each party's working interest. On April 4, 2024, the Expert found in favour of Alvopetro S.A., increasing Alvopetro S.A.'s working interest from 49.1% to 56.2%. The Partner filed a notice of dispute and Alvopetro then filed a request for emergency arbitration. On May 10, 2024, the parties received the Order of the emergency arbitrator wherein the arbitrator found in favour of Alvopetro, making the Expert decision effective June 1, 2024 until such time as the dispute was reviewed and decided by an arbitral tribunal pursuant to the Rules of Arbitration of the ICC. The full arbitration under the ICC commenced in May 2024 wherein Alvopetro seeks recognition by the Arbitral Tribunal of the binding nature of the Expert decision, with Alvopetro's working interest maintained at 56.2%. The Partner is seeking a declaration by the Tribunal that the Expert decision is invalid and ineffective such that a new redetermination can be carried out. In December 2024, the Arbitral Tribunal was confirmed by the Secretary General of the ICC. Throughout 2025, each party presented arguments to the Arbitral Tribunal and responses to arguments of the other party. An arbitration hearing was held in September 2025 and final submissions have now been made to the Arbitral Tribunal.

The Company is involved in a legal dispute with respect to the computation of the GORR on natural gas from Block 197. Pursuant to dispute resolution provisions, the arbitration procedure was filed in 2021 under the Rules of Arbitration of the ICC. In April 2025 Alvopetro received the findings of the arbitral tribunal wherein the tribunal found in favour of the GORR holders requiring Alvopetro to adjust the sales price used in the computation of the GORR. Alvopetro was required to submit all calculations of the additional GORR owing to the tribunal for review and the parties are currently discussing the respective calculations.

During the financial year ended December 31, 2025, there have been: (i) no penalties or sanctions imposed against Alvopetro by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against Alvopetro that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements Alvopetro entered into before a court relating to securities legislation or with a securities regulatory authority.

AUDIT COMMITTEE

General

The Audit Committee is governed by its mandate which is attached hereto in Schedule F. This mandate provides that the Audit Committee be comprised of at least three members of the Board, all of whom are considered independent and financially literate within the meaning of National Instrument 52-110 – *Audit Committees* ("NI 52-110").

The Corporation has established an Audit Committee comprised of three members: Firoz Talakshi (Chair), Kenneth R. McKinnon and Roderick L. Fraser. Each audit committee member is independent and financially literate. The following is a brief summary of the education or experience of each member of the Audit Committee that is relevant to the performance of his mandated responsibilities:

Name of Audit Committee Member	Relevant Education and Experience
Firoz Talakshi	Mr. Talakshi's past positions as Senior Advisor and, prior thereto, Partner with KPMG International Corporate Tax, Calgary have both developed and required the skills to analyze financial statements, to understand accounting principles and application of such and to understand internal controls with respect to financial reporting. In his positions with KPMG he gained a significant depth of understanding with respect to complex financial accounting and international tax issues. Mr. Talakshi was qualified as a Chartered Accountant in England and Wales in 1973 and was a member of the Chartered Professional Accountants of Alberta.
Kenneth R. McKinnon	Mr. McKinnon's understanding of audit committee roles and responsibilities has been obtained through various audit committee appointments, since 2000, for several reporting issuers: Touchstone Exploration Inc. (formerly Petrobank Energy and Resources Ltd.); Supreme Cannabis Company, Inc.; Lightstream Resources Ltd.; and Petrominerales Ltd. Mr. McKinnon also held the position Vice President Legal and General Counsel of Critical Mass Inc., a website design company from March 2000 to December 2014. Mr. McKinnon holds a Bachelor of Commerce degree from the University of Calgary and a Bachelor of Law degree from Queens University. His ICD.D designation as a certified corporate director has further enhanced his understanding of accounting principles, internal controls and analyzing financial statements.
Roderick L. Fraser	Mr. Fraser has a significant breadth of experience in the energy industry, ranging from positions in operations to investment banking. He has held various positions with major international banks including Managing Director and Head of Oil & Gas for MUFG Union Bank and Managing Director and Global Head of Oil and Gas, Standard Bank of South Africa. Much of his banking career has been spent supporting junior exploration and production and services companies develop and implement growth initiatives in emerging markets. These positions have provided Mr. Fraser with an understanding of accounting principles and significant experience in analyzing and evaluating financial statements. Mr. Fraser has also been contracted as an independent consultant for large financial institutions. Mr. Fraser is a petroleum engineer with over 40 years of experience in the oil and gas sector.

External Auditor Fees

The auditor of the Corporation is KPMG LLP, first appointed as auditors effective May 3, 2021, and approved in the annual general and special meeting on August 12, 2021. The following table sets forth the aggregate fees billed by KPMG LLP for the years-ended December 31, 2025 and December 31, 2024.

Year ended	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
2025	C$327,792	C$72,600	C$19,523	-
2024	C$356,296	C$70,620	C$19,392	-

Audit fees were paid, or are payable, for professional services rendered by the auditors for the audit of the annual financial statements. Audit related fees relate to fees paid or payable for reviews of the quarterly financial statements. Tax fees relate to tax compliance fees. All other fees relate to services other than those as described as audit fees, audit related frees or tax fees.

The Audit Committee is required to pre-approve all non-audit services to be provided to the Corporation by the external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member(s) report to the Audit Committee at the next scheduled meeting and the member comply with such other procedures as may be established by the Audit Committee from time to time. In the most recent two years audit and audit related fees were paid for professional services rendered by the auditors for the audit of the annual financial statements and reviews of the quarterly financial statements.

At no time since the commencement of the most recently completed financial year, has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board of Directors.

As a venture issuer within the meaning ascribed thereto in NI 52-110, the Corporation is relying upon the exemption in section 6.1 of NI 52-110.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the directors or executive officers of Alvopetro or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than ten percent of the Common Shares, or any associate or affiliate of any of the foregoing persons or companies, has or has had any material interest, direct or indirect, in any transaction within the last three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Alvopetro.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Auditors

The independent auditor of Alvopetro is KPMG LLP, 2200, 240 4 Avenue S.W., Calgary, Alberta, T2P 4H4. KPMG LLP was first appointed as the Corporation's auditor effective May 3, 2021 by the Board and approved in the annual general and special meeting held by the Corporation on August 12, 2021.

Transfer Agent and Registrar

TSX Trust Company, at its principal offices in Calgary, Alberta, is the registrar and transfer agent for the Common Shares.

MATERIAL CONTRACTS

In 2018, the Company entered into the GSA to outline the terms of the supply of natural gas to Bahiagás, the natural gas distribution company in the state of Bahia. The agreement was amended in each of 2020 to 2024 as discussed above (see "*General Development of the Business – Three Year History*"). The original agreement and the amendments have been filed by the Company and may be accessed through the Company's SEDAR+ profile (www.sedarplus.ca).

In 2025, the Company entered into the 2025 Loan. See "*Description of Capital Structure - Bank Debt*". The 2025 Loan agreement has been filed by the Company and may be accessed through the Company's SEDAR+ profile (www.sedarplus.ca).

INTERESTS OF EXPERTS

GLJ prepared the GLJ Reserves and Resources Report, the results of which are summarized in this Annual Information Form. As at the date of the GLJ Reserves and Resources Report, GLJ is independent within the meaning of NI 51-101. GLJ and the engineers and geologists responsible for the preparation of the report, individually or as a group, have no interest, direct or indirect, nor do they expect to receive any interest, direct or indirect, in the properties or in the securities of Alvopetro. The partners, employees or consultants of GLJ (as a group) beneficially own less than one percent of any class of the Company's outstanding securities.

KPMG LLP is the independent auditor of Alvopetro and has confirmed that it is independent with respect to Alvopetro within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information concerning Alvopetro may be found under Alvopetro's profile on SEDAR+ at www.sedarplus.ca. Additional information, including information concerning directors' and officers' remuneration and indebtedness, principal holders of Alvopetro securities and securities authorized for issuance under equity compensation plans, will be contained in the information circular of Alvopetro in respect of the annual general and special meeting of holders of Common Shares which will be held later this year. Additional financial information is provided in Alvopetro's audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2025.

SCHEDULE A

REPORT ON RESERVES DATA, CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR (FORM 51-101F2)

Effective date: December 31, 2025

(attached)

FORM 51-101F2

REPORT ON RESERVES DATA, CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Alvopetro Energy Ltd. (the "Company"):

1. We have evaluated the Company's reserves, contingent resources and prospective resources data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, estimated using forecast prices and costs. The contingent resources and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related to risked net present value of future net revenue as at December 31, 2025, estimated using forecast prices and costs.

2. The reserves, contingent resources and prospective resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves, contingent resources and prospective resources data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves, contingent resources and prospective resources data are free of material misstatement. An evaluation also includes assessing whether the reserves, contingent resources and prospective resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2025, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – US M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	Dec. 31, 2025	Brazil	-	384,741	-	**384,741**
GLJ Ltd.	Dec. 31, 2025	Canada	-	8,854	-	**8,854**
Total				393,595		**393,595**

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to best estimate contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent

and prospective resources data that we have evaluated and reported on to the Company's board of directors:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – US M$)		
					Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Ltd.	Dec 31, 2025	Brazil	3,805	-	88,031	**88,031**

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – US M$)		
					Audited	Evaluated	Total
Prospective Resources (2U)	GLJ Ltd.	Dec 31, 2025	Brazil	12,136	-	264,254	**264,254**

7. In our opinion, the reserves, contingent resources and prospective resources data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves, contingent resources and prospective resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

9. Because the reserves, contingent resources and prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, February 25, 2026

"Originally Signed By"

Patrick A. Olenick, P. Eng.
Senior Vice President, International Evaluations

SCHEDULE B

DISCLOSURE OF CONTINGENT AND PROSPECTIVE RESOURCE DATA EFFECTIVE DECEMBER 31, 2025

Capitalized terms not specifically defined in this Schedule B have the meaning ascribed to them in the Annual Information Form to which this schedule is attached.

Contingent and prospective resources should not be confused with reserves and readers should review the section titled "Resources" within the section "Notes on Reserves Data and Other Oil and Natural Gas Information" included within this AIF for additional information including risks associated with resource estimates. There is no guarantee that the estimated resources will be recovered. There is uncertainty that it will be commercially viable to produce any portion of the resources. Actual recovered resources may be greater than or less than the estimates provided herein. Actual natural gas resources may be greater than or less than the estimates provided herein. There is no certainty that any portion of the prospective resources will be discovered and even if discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Readers should also review the "Risk Factors" section in this AIF for a broader discussion of the risks and uncertainties facing the Company.

The GLJ Reserves and Resources Report includes Contingent and Prospective Resources and has been prepared in accordance with the standards contained in the COGE Handbook that are consistent with the standards of NI 51-101. GLJ is a qualified reserves evaluator as defined in NI 51-101. The GLJ Reserves and Resources Report included an evaluation of the natural gas resources of the Murucututu natural gas field. Alvopetro's working interest in the Murucututu natural gas field is 100%. In addition to the reserves assigned by GLJ to the Murucututu field as described in the Annual Information Form to which this schedule is attached, contingent resource was assigned to the area in proximity to the existing Murucututu reserves, deemed to be discovered. The area mapped by 3D seismic west and north of the area defined as contingent was assigned as prospective resources.

December 31, 2025 Murucututu Contingent Resources

Summary of Unrisked Company Gross Contingent Resources (2)(3)(4)(5)

Development Pending Economic Contingent Resources	Low Estimate	Best Estimate	High Estimate
Conventional natural gas (MMcf)	11,970	22,671	32,222
Natural gas liquids (Mbbl)	237	449	638
Oil equivalent (Mboe)	**2,232**	**4,228**	**6,009**

See 'Footnotes' section

Summary of Unrisked Company Net Contingent Resources (2)(3)(4)(5)

Development Pending Economic Contingent Resources	Low Estimate	Best Estimate	High Estimate
Conventional natural gas (MMcf)	11,168	21,152	30,063
Natural gas liquids (Mbbl)	221	419	596
Oil equivalent (Mboe)	**2,083**	**3,944**	**5,606**

Summary of Before Tax Net Present Value of Future Net Revenue of Unrisked Contingent Resources – Forecast Prices and Costs - $000s (2)(3) (4)(5)

	Undiscounted	5%	10%	15%	20%
Low Estimate	118,454	69,790	44,091	29,296	20,196
Best Estimate	280,417	155,795	97,812	66,230	47,116
High Estimate	447,527	221,191	133,388	89,144	63,227

See 'Footnotes' section

The table below sets out the project development costs assumed in the GLJ Reserves and Resources Report in the estimation of future net revenue attributable to contingent resources and assumes capital deployment starting in 2029 for the drilling of wells and first commercial production in 2029. The recovery technology assumed for purposes of the estimate is based on established technologies utilized repeatedly in the industry.

There can be no certainty that the project will be developed on the timelines discussed herein. The project is based on a pre-development study. Development of the project is dependent on several contingencies as further described in this AIF. Significant positive factors relevant to the estimate include existing production in close proximity, proximity to infrastructure, existing long-term gas sales agreement and corporate commitment to the project. Significant negative factors relevant to the estimate include reservoir performance and the economic viability of the project (with sensitivity to low commodity prices), access to and amount of capital required to develop resources at an acceptable cost, and regulatory approvals for planned activities including stimulations and new infrastructure developments.

Assumed Project Development Costs for Unrisked Contingent Resources (2)(3)(4)(5)

$millions	Low Estimate	Best Estimate	High Estimate
2026	-	-	-
2027	-	-	-
2028	-	-	-
2029	15.2	15.2	15.2
2030	25.0	25.0	25.0
Remaining Years	-	-	-
Total Undiscounted	**40.2**	**40.2**	**40.2**

See 'Footnotes' section

Projected 10 Year Production Profile of Company Gross Sales Gas for Contingent Resources (2)(3) (4)(5)

Mcfpd	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Estimate	-	-	-	3,269	5,984	4,643	3,164	2,408	1,947	1,634
Best Estimate	-	-	-	5,131	9,503	7,574	5,303	4,121	3,389	2,886
High Estimate	-	-	-	6,068	11,324	9,205	6,583	5,204	4,339	3,739

See 'Footnotes' section

Summary of Development Pending Risked Company Contingent Resources(2)(3) (4)(5)

The GLJ Reserves and Resources Report estimates the Chance of Development as the product of two main contingencies associated with the project development, which are: 1) the probability of corporate sanctioning, which GLJ estimates at 95%; and 2) the probability of finalization of a development plan, which GLJ estimates at 95%. The product of these two contingencies is 90%. As there is no risk related to discovery, the Chance of Commerciality for the contingent resource is therefore 90% which is the risk factor that has been applied to the Development Risked company gross contingent resources and the net present value figures reported below.

Company Gross	**Low Estimate**	**Best Estimate**	**High Estimate**
Conventional natural gas (MMcf)	10,773	20,404	29,000
Natural gas liquids (Mbbl)	213	404	575
Oil equivalent (Mboe)	**2,009**	**3,805**	**5,408**

See 'Footnotes' section

Company Net	**Low Estimate**	**Best Estimate**	**High Estimate**
Conventional natural gas (MMcf)	10,052	19,037	27,057
Natural gas liquids (Mbbl)	199	377	536
Oil equivalent (Mboe)	**1,874**	**3,550**	**5,046**

Summary of Development Pending Risked Before Tax Net Present Value of Future Net Revenue of Contingent Resources – Forecast Prices and Costs - $000s(2)(3)(4)(5)

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

	Undiscounted	5%	10%	15%	20%
Low Estimate	106,609	62,811	39,682	26,366	18,177
Best Estimate	252,375	140,215	88,031	59,607	42,404
High Estimate	402,774	199,072	120,049	80,230	56,904

See 'Footnotes' section.

<u>December 31, 2025 Murucututu Prospective Resources</u>

Summary of Unrisked Company Gross Prospective Resources (1)(3)

Prospective Resources	Low Estimate	Best Estimate	High Estimate
Conventional natural gas (MMcf)	37,477	80,346	137,132
Natural gas liquids (Mbbl)	743	1,592	2,717
Oil equivalent (Mboe)	**6,989**	**14,983**	**25,573**

See 'Footnotes' section

Summary of Unrisked Company Net Prospective Resources (1)(3)

Prospective Resources	Low Estimate	Best Estimate	High Estimate
Conventional natural gas (MMcf)	34,966	74,963	127,944
Natural gas liquids (Mbbl)	693	1,485	2,535
Oil equivalent (Mboe)	**6,520**	**13,979**	**23,859**

See 'Footnotes' section

Summary of Before Tax Net Present Value of Future Net Revenue of Unrisked Prospective Resources – Forecast Prices and Costs- $000s (1)(3)

	Undiscounted	5%	10%	15%	20%
Low Estimate	450,215	246,095	147,484	94,425	63,476
Best Estimate	1,114,346	561,501	326,240	207,124	139,485
High Estimate	2,119,375	959,953	537,525	337,051	226,133

See 'Footnotes' section

The table below sets out the project development costs assumed in the GLJ Reserves and Resources Report in the estimation of future net revenue attributable to prospective resources. Capital deployment is assumed to start in 2029 for the drilling of wells, expansion of field facilities and additional pipeline capacity. First commercial production is assumed in 2029. The information presented herein is based on company project development costs. The recovery technology assumed for purposes of the estimate is based on established technologies utilized repeatedly in the industry.

There can be no certainty that the project will be developed on the timelines discussed herein. Development of the project is dependent on several contingencies as further described in this AIF. The project is based on a conceptual study. Significant positive factors relevant to the estimate include existing production in close proximity, proximity to infrastructure, existing long-term gas sales agreement and corporate commitment to the project. Significant negative factors relevant to the estimate include reservoir performance and the economic viability of the project (with sensitivity to low commodity prices), access to and amount of capital required to develop resources at an acceptable cost, and regulatory approvals for planned activities including stimulations and new infrastructure developments.

Assumed Project Development Costs for Unrisked Prospective Resources (1)(3)

$millions	Low Estimate	Best Estimate	High Estimate
2026	-	-	-
2027	-	-	-
2028	-	-	-
2029	5.4	5.4	5.4
2030	8.4	8.4	8.4
Remaining Years	86.4	113.2	122.2
Total Undiscounted	100.2	127.0	136.0

See 'Footnotes' section

Projected 10 Year Production Profile of Company Gross Sales Gas for Prospective Resources(1)(3)

Mcfpd	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Estimate	-	-	-	4,132	3,650	8,336	12,542	13,469	9,655	7,246
Best Estimate	-	-	-	6,141	7,866	13,322	18,756	22,735	21,179	15,641
High Estimate	-	-	-	7,333	12,112	19,332	26,258	31,583	32,281	24,697

See 'Footnotes' section

Summary of Development and Discovery Risked Company Prospective Resources(1)(3)

The GLJ Reserves and Resources Report estimates the Chance of Commerciality as the product between the Chance of Discovery and the Chance of Development. The Chance of Discovery of the prospective resources has been assessed at 90%, while the Chance of Development has been assessed as the same as for the Contingent Resources described above at 90%. The resulting Chance of Commerciality is 81%, which has been applied to the company gross unrisked prospective resources and the net present value figures reported below.

Company Gross	Low Estimate	Best Estimate	High Estimate
Conventional natural gas (MMcf)	30,356	65,081	111,077
Natural gas liquids (Mbbl)	602	1,290	2,201
Oil equivalent (Mboe)	**5,661**	**12,136**	**20,714**

See 'Footnotes' section

Company Net	Low Estimate	Best Estimate	High Estimate
Conventional natural gas (MMcf)	28,322	60,720	103,634
Natural gas liquids (Mbbl)	561	1,203	2,054
Oil equivalent (Mboe)	**5,282**	**11,323**	**19,326**

Summary of Development Risked Before Tax Net Present Value of Future Net Revenue of Prospective Resources – Forecast Prices and Costs - $000s(1)(3)

An estimate of risked net present value of future net revenue of prospective resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes prospective resources that are considered too uncertain with respect to the chance of development and chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

	Undiscounted	5%	10%	15%	20%
Low Estimate	364,674	199,337	119,462	76,484	51,416
Best Estimate	902,620	454,816	264,254	167,771	112,983
High Estimate	1,716,694	777,562	435,395	273,011	183,168

See 'Footnotes' section

Footnotes:

(1) Prospective Resources – Prospective Resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the prospective resources will be discovered and even if discovered, there is no certainty that it will be commercially viable to produce any portion. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery as described in footnote (3).

(2) Contingent Resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

(3) *Low Estimate*: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(4) The Contingent Resources estimated in the GLJ Reserves and Resources Report are classified as "economic contingent resources", which are those contingent resources that are currently economically recoverable. All such resources are further sub-classified with a project status of "development pending", meaning that resolution of the final conditions for development are being actively pursued.

(5) The recovery estimates of the Company's contingent resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. There is uncertainty that it will be commercially viable to produce any portion of the resources. Actual recovered resource may be greater than or less than the estimates provided herein.

Pricing Assumptions – Forecast Prices and Costs

GLJ employed the following pricing and inflation rate assumptions as of December 31, 2025 in the GLJ Reserves and Resources Report in estimating resources.

Year	Inflation %	Brent Blend Crude Oil FOB North Sea ($/Bbl)	NYMEX Henry Hub Near Month Contract ($/MMBtu)	Alvopetro-Bahiagas Gas Contract $/MMBtu[1]
2026	0.0	63.25	3.98	8.65
2027	2.0	70.00	4.00	8.72
2028	2.0	74.08	4.16	9.98
2029	2.0	76.32	4.25	10.19
2030	2.0	77.84	4.33	10.27
2031	2.0	79.41	4.42	10.48
2032	2.0	81.00	4.50	10.69
2033	2.0	82.61	4.60	10.90
2034	2.0	84.26	4.69	11.12
2035	2.0	85.95	4.78	11.34
2036+[2]	2.0/year	+2.0%/yr	+2.0%/yr	+2.0%/yr

(1) *Net of sales taxes expected to apply*
(2) *Escalated at a rate of 2.0% per year thereafter.*

SCHEDULE C

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-101F3)

Terms to which a meaning is ascribed in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Alvopetro Energy Ltd. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes other information such as contingent resources data and prospective resources data.

An independent qualified reserves evaluator has evaluated and reviewed the Corporation's reserves data, contingent resources data and prospective resources data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to the Annual Information Form of the Corporation for the year ended December 31, 2025 (the "**AIF**").

The Reserves Committee of the Board of Directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator, GLJ Ltd. ("**GLJ**");

(b) met with GLJ to determine whether any restrictions affected the ability of GLJ to report without reservation; and

(c) reviewed the reserves data, contingent resources data and prospective resources data with management and with GLJ.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1, incorporated into the AIF, containing reserves data, contingent resources data, prospective resources data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the report of GLJ on the reserves data, the contingent resources data and the prospective resources data; and

(c) the content and filing of this report.

Because the reserves data, the contingent resources data and the prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Corey C. Ruttan"
Corey C. Ruttan, President & Chief Executive Officer

(signed) "Adrian Audet"
Adrian Audet, Vice President, Asset Management

(signed) "John D. Wright"
John D. Wright, Chairman and Director

(signed) "Geir Ytreland"
Geir Ytreland, Director & Chairman of the Reserves Committee

March 17, 2026

SCHEDULE D

AUDIT COMMITTEE MANDATE

Role and Objective

The Audit Committee is a committee of the Board of Directors of Alvopetro Energy Ltd. (the "Corporation") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited consolidated financial statements and other mandatory disclosure releases containing financial information of the Corporation.

The objectives of the Audit Committee are as follows:

1. to assist directors in fulfilling their legal and fiduciary obligations (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to oversee the audit efforts of the external auditors of the Corporation;

3. to maintain free and open means of communication among the directors, the external auditors, the financial and senior management of the Corporation;

4. to satisfy itself that the external auditors are independent of the Corporation; and

5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

The function of the Committee is one of oversight of management and the external auditors in the execution of their responsibilities. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation, maintaining appropriate accounting and financial reporting principles and policies and implementing appropriate internal controls and procedures. The external auditors are responsible for planning and carrying out a proper audit of the annual financial statements of the Corporation and reviewing the financial statements of the Corporation prior to their filing with securities regulatory authorities and other procedures.

Composition of the Committee

1. The Audit Committee shall consist of at least three directors. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.

2. Each director appointed to the Audit Committee by the Board must be independent. A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – *Audit Committees* or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

Meetings of the Committee

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the quarterly financial statements and management discussion and analysis of the Corporation.

2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.

3. Notice of a meeting of the Audit Committee shall:

   (a) be given orally, or in writing, including by email;

   (b) state the nature of the business to be transacted at the meeting in reasonable detail;

   (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and

   (d) be given at least two days prior to the time stipulated for the meeting.

   (a) A member may in any manner waive notice of the meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting.

4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee.

5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

7. The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet *in camera* with the external auditors independent of management as necessary, in the sole discretion of the Committee, and (ii) may meet separately with management.

8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Duties and Responsibilities of the Committee

1. It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.

2. The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.

3. It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that the Corporation's system of internal controls over financial reporting and disclosure controls and procedures are satisfactory for the purpose of:

   (a) identifying, monitoring and mitigating the principal risks intended to be addressed by such controls and procedures;

   (b) complying with the legal and regulatory requirements related to such controls and procedures;

and to review with the external auditors their assessment of the internal controls over financial reporting and the disclosure controls of the Corporation, their written reports containing recommendations for improvement, and management's response and any follow-up to any identified weaknesses.

4. It is the responsibility of the Audit Committee to review the annual financial statements of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should include but be not to be limited to:

   (a) reviewing and accepting/approving, if appropriate, the annual audit plan of the external auditors of the Corporation, including the scope of audit activities, and monitor such plan's progress and results during the year;

   (b) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

   (c) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   (d) reviewing the methods used to account for significant unusual or non-recurring transactions;

   (e) reviewing compliance with covenants under loan agreements;

   (f) reviewing disclosure requirements for commitments and contingencies;

   (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   (h) reviewing unresolved differences between management and the external auditors;

   (i) obtain explanations of significant variances with comparative reporting periods;

   (j) review of business systems changes and implications;

   (k) review of authority and approval limits;

   (l) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors and management;

   (m) confirm through private discussion with the external auditors and the management that no management restrictions are being placed on the scope of the external auditors' work;

   (n) review of tax policy issues; and

   (o) review of emerging accounting issues that could have an impact on the Corporation.

5. It is the responsibility of the Audit Committee to review the interim financial statements of the Corporation and, if deemed appropriate, to recommend the financial statements to the Board for approval and to review all prospectuses, management discussion and analysis, annual information forms and all other public disclosure containing significant audited or unaudited financial information. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

6. The Audit Committee shall have the authority to:

   (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

   (b) discuss with the management and senior staff of the Corporation, its subsidiaries and affiliates, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

(c) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

(d) to set and pay the compensation for any advisors employed by the Audit Committee.

7. With respect to the appointment of external auditors by the Board, the Audit Committee shall:

(a) recommend to the Board the appointment of the external auditors;

(b) review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;

(c) oversee the independence of the external auditors by, among other things, if determined necessary, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;

(d) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and that the external auditors shall report directly to the Committee; and

(e) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

8. The Audit Committee shall review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

9. The Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting and such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

10. The Audit Committee shall review adherence to the risk management policies and procedures of the Corporation (i.e. hedging, litigation and insurance), including an annual review of insurance coverage, and make appropriate recommendations to the Board with respect thereto.

11. The Audit Committee shall establish and maintain procedures for:

(a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting controls, or auditing matters; and

(b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

12. The Audit Committee shall review and approve the Corporation's hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.

13. The Audit Committee shall periodically report the results of reviews undertaken and any associated recommendations to the Board.

14. The Audit Committee shall review and assess, on an annual basis, the adequacy of this Mandate.