TENAZ ENERGY

TENAZ ENERGY CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2021

March 24, 2022

CERTAIN DEFINITIONS

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 (as defined below) or the COGE Handbook (as defined below) and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended, including any regulations promulgated thereunder;

"**AER**" means the Alberta Energy Regulator;

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

"**Altura**" means Altura Energy Inc. or the predecessor corporation of the Company prior to the amalgamation of Tenaz Energy Corp. and Altura Energy Inc. on October 15, 2021 under the ABCA;

"**Audit Committee**" means the audit committee of the Board;

"**Board**" or "**Board of Directors**" means the board of directors of the Company;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

"**Common Share**" or "**Common Shares**" means, respectively, one or more common shares in the capital of the Company. Effective December 23, 2021, the Company completed the Share Consolidation on the basis of one new Common Share for every ten existing Common Shares;

"**development costs**" means costs incurred to develop reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from 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, 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 cost 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 hydrocarbon recovery systems;

"**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 crude oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property;

"**gross**" means:

a) In relation to the Company's interest in production and reserves, its "Company gross reserves", which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

b) In relation to wells, the total number of wells in which the Company has an interest; and

c) In relation to properties, the total area of properties in which the Company has an interest;

"**IFRS**" means International Financial Reporting Standards;

"**LLR**" means Licensee Liability Rating;

"**McDaniel**" means McDaniel & Associates Consultants Ltd.;

"**McDaniel Report**" means the independent reserves assessment prepared by McDaniel dated March 18, 2022 evaluating the oil and gas properties of the Company effective December 31, 2021 in accordance with NI 51-101;

"**net**" means:

a) In relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;

b) In relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

c) In relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

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

"Reorganization" has the meaning ascribed thereto under the heading "*General Development of the Business – 3-Year History - 2021*";

"Share Consolidation" has the meaning ascribed thereto under the heading "*General Development of the Business – 3-Year History – 2021*";

"**Shareholders**" means the holders from time to time of Common Shares;

"**Stock Option**" or "**Stock Options**" means, respectively, one or more options to purchase Common Shares granted under the Company's stock option plan;

"**Tenaz**" or the **"Company"** means Tenaz Energy Corp., a corporation existing under the ABCA;

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

"**U.S.**" or "**United States**" means the United States of America; and

"**Warrant**" has the meaning ascribed thereto under the heading "*Description of Share Capital*".

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. The information set out in this Annual Information Form is stated as at December 31, 2021 unless otherwise indicated and except that information in documents incorporated by reference herein is given as of the dates noted therein.

SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel of oil or NGLs	Mcf	thousands of cubic feet
bbls	barrels of oil or NGLs	Mcfe	thousands of cubic feet equivalent
bbls/d	barrels per day	MMcf	millions of cubic feet
Mbbl	thousands of barrels of oil or NGLs	Mcf/d	thousands of cubic feet per day
NGLs	natural gas liquids	Mcfe/d	thousands of cubic feet equivalent per day

API	American Petroleum Institute
° API	is an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specific gravity of 31.1º API or higher is generally referred to as light crude oil
boe	barrel of oil equivalent of natural gas and crude oil on the basis of one bbl for six Mcf of natural gas
boe/d	barrel of oil equivalent per day
Mboe	1,000 barrels of oil equivalent
M$	thousands of dollars
OPEC	Organization of Petroleum Exporting Countries
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

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	Cubic feet	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

CURRENCY OF INFORMATION

In this AIF, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

OIL AND GAS ADVISORIES

Caution Respecting boe

In this AIF, the abbreviation boe means barrel of oil equivalent on the basis of 6 Mcf to 1 boe of natural gas when converting natural gas to boe. boe 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.

ADDITIONAL NON-GAAP AND OTHER FINANCIAL MEASURES

This AIF includes references to certain financial and performance measures which do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures disclosed by other issuers. These measures include:

- Operating netback: Tenaz calculates operating netback on a per boe basis, as petroleum and natural gas sales less royalties, operating costs and transportation costs. Operating netback is a key industry benchmark and a measure of performance for Tenaz that provides investors with information that is commonly used by other crude oil and natural gas producers. The measurement on a per boe basis assists management and investors with evaluating operating performance on a comparable basis. Information is included in this document by reference. More information and a reconciliation to primary financial statement measures can be found within the "Non-GAAP and Other Financial Measures " section of the December 31, 2021 MD&A available on SEDAR at www.sedar.com.

In addition, this AIF includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures. These non-GAAP financial measures are unlikely to be comparable to similar financial measures presented by other issuers. These non-GAAP financial measures include:

- Capital expenditures: Represents the Company's of capital investment in exploration and production activity. Information is included in this document by reference, more information and a reconciliation to primary financial statement measures can be found within the "Non-GAAP Financial Measures" section of the December 31, 2021 MD&A available on SEDAR at www.sedar.com.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain information set forth in this Annual Information Form, including certain documents incorporated by reference into this Annual Information Form, contain forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast", "will" or other similar words and include statements relating to or associated with individual wells, facilities, regions or projects. Any statements regarding the following are forward-looking statements:

- uncertainty about the COVID-19 pandemic and the impact it will have on Tenaz's operations, the demand for Tenaz's products, and economic activity in general;
- the performance characteristics of the Company's crude oil and natural gas properties;
- future crude oil, NGLs and natural gas prices;
- future production levels and production levels by commodity;
- future drilling, completion and tie-in of wells;
- development plans for proved and probable undeveloped reserves;
- anticipated land expiries;
- future facility access, acquisition or construction;
- future availability of financing, future sources of funding for capital programs and future availability of such sources;
- availability of credit facilities;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future decommissioning costs and the related discount rates and inflation factors used to determine such estimates;
- development plans;
- 2022 capital budget and production guidance;
- future development potential on the Company's lands;
- expectations with respect to future growth and opportunities;
- treatment under governmental regulatory regimes and tax and royalty laws;
- the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on the Company;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and geographical areas developed; and
- changes to any of the foregoing.

With respect to forward-looking statements contained in this Annual Information Form, including certain documents incorporated by reference into this Annual Information Form, the Company has made assumptions regarding:

- the continued performance of the Company's crude oil and natural gas properties in a manner consistent with its past experiences;
- that the Company will continue to conduct its operations in a manner consistent with past operations;
- the return of industry conditions to pre-COVID-19 pandemic levels;
- crude oil, NGLs and natural gas production rates;
- the size of crude oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for crude oil, NGLs and natural gas;
- the success of the Company's operations and exploration and development activities;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling equipment;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- future abandonment, decommissioning and reclamation costs;
- general economic and financial market conditions;
- tax horizons;
- the success, nature and timing of enhanced recovery activities;

- the ability of the Company to secure necessary personnel, equipment and services;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of exploration and development activities; and
- access to market for the Company's production.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include:

- changes in commodity prices including, without limitation, as a result of the COVID-19 pandemic and related disruptions in crude oil and natural gas markets;
- industry conditions, including commodity prices;
- pipeline and third-party facility capacity constraints and access to sales markets;
- volatility of commodity prices and currency exchange rates;
- imprecision of reserve estimates and related costs including royalties, production costs and future development costs;
- environmental risks;
- stock market volatility;
- ability to access sufficient capital from internal and external sources and the ability of the Company to realize value from acquired assets and companies;
- debt financing risks;
- failure to realize anticipated benefits of acquisitions and dispositions;
- risks inherent in oil and natural gas operations;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- success of drilling programs;
- geological, technical, drilling, completion and processing problems;
- results of enhanced recovery responses;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "Risk Factors".

All of these factors should be considered in the context of current economic conditions, in particular, volatility in commodity prices, including low prices for crude oil and natural gas over the past several years, the attitude of lenders and investors towards crude oil and natural gas assets, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company.

Ultimate recovery of reserves is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management of the Company.

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

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

References to forward-looking information are made elsewhere in this Annual Information Form. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

THE COMPANY

Tenaz is the corporation resulting from the amalgamation of Tenaz Energy Corp. and Altura Energy Inc. on October 15, 2021 under the ABCA.

On June 8, 2007, Altura Energy Inc. was incorporated under the ABCA under the name of "Northern Spirit Developments Inc.". On November 2, 2007, "Northern Spirit Developments Inc." filed articles of amendment to change its name to "Northern Spirit Resources Inc.". On January 1, 2012, "Northern Spirit Resources Inc." filed articles of amalgamation to amalgamate with Northern Spirit Operating Inc. and 1250900 Alberta Ltd. On October 16, 2015, "Northern Spirit Resources Inc." filed articles of amendment to change its name to "Altura Energy Inc.". On October 15, 2021, in connection with the Reorganization, Altura Energy Inc. filed articles of amalgamation and changed its name to "Tenaz Energy Corp.".

The Company is a reporting issuer (or the equivalent thereof) in Alberta, British Columbia and Ontario. The Common Shares are listed and posted for trading on the TSXV under the symbol "TNZ". Prior to October 19, 2021, the Common Shares traded on the TSXV under the symbol "ATU" and prior to October 19, 2015, the Common Shares traded on the TSXV under the symbol "NS".

The Company has one wholly owned subsidiary, 1880675 Alberta Ltd., a corporation existing under the ABCA.

The Company's registered office is located at 1100, 225 – 6th Avenue S.W., Brookfield Place, Calgary, Alberta T2P 1N2, and its head and principal office is located at 2500, 605 – 5th Avenue S.W., Calgary, Alberta, T2P 3H5.

GENERAL DEVELOPMENT OF THE BUSINESS

3-Year History

The following is a summary of the general development of the Company's business during the last three completed financial years.

2019

During the year ended December 31, 2019, Altura executed a $9.4 million capital program, net of divestitures totaling $3.5 million. Altura drilled three and completed two wells at Leduc-Woodbend and drilled a vertical exploratory stratigraphic well in a new area called Entice, located south of Strathmore, Alberta. Additionally, Altura changed its artificial lift system on 11 wells totaling $0.8 million of workover expenditures and $1.2 million related to equipping expenditures. Average production for the year was 1,742 boe/d.

In December 2019, pursuant to a definitive agreement with an unrelated third party, Altura committed to: (i) the sale, in two transactions, of a 12.5% working interest in the Company's production, wells, lands and facilities for total cash consideration of $7.0; (ii) subject to mutual agreement and in certain circumstances, the sale of an additional 4.0% of corporate assets for $3.0 million; and (iii) certain capital commitments in the Entice and/or Leduc-Woodbend areas. In December 2019, Altura closed the first transaction and divested a 7.0% working interest of the Company's production, wells, lands and facilities for total cash consideration of $3.5 million.

2020

During the year ended December 31, 2020, Altura executed a $6.1 million capital program, net of divestitures totaling $1.7 million. In March 2020, Altura halted all discretionary capital expenditures in response to the impacts of COVID-19 on the global economy. Prior to the COVID-19 pandemic, Altura completed a Leduc-Woodbend horizontal oil well (93% working interest) that was drilled in the third quarter of 2019 and drilled a

Leduc-Woodbend horizontal oil well (93% working interest) that was completed in February 2021. At Entice, Altura incurred $4.0 million to drill, complete, and equip a well targeting the Pekisko Formation.

Average production for 2020 was 880 boe/d following: (i) voluntarily curtailed production in April 2020 to match its hedged oil production in response to the COVID-19 pandemic and disruptions in the crude oil and natural gas markets; and (ii) a shut in of all production in May 2020 and the unwinding of its May 2020 hedging contracts.

In June 2020, Altura: (i) amended the December 2019 disposition agreement which divided the second transaction into four separate dispositions of a 1.375% working interest for $875,000 each; (ii) did not execute the optional third transaction contemplated per the December 2019 disposition; and (iii) as part of stage one to the amended December 2019 disposition agreement, divested the first 1.375% working interest in the Company's production, wells, lands and facilities for cash of $871,000.

In September 2020, as part of stage two to the amended December 2019 disposition agreement, Altura divested the second 1.375% working interest in the Company's production, wells, lands and facilities for cash of $875,000.

2021

During the year ended December 31, 2021, the Company entered into a reorganization agreement in addition to executing a $8.6 million capital program, net of divestitures totaling $1.7 million. The Company drilled three and completed four wells at Leduc-Woodbend, and completed 12 rod upgrades and one recompletion at Leduc-Woodbend. Average production for the year was 1,015 boe/d.

In 2021, the Company divested the remaining 2.75% working interest in the Company's production, wells, lands and facilities for cash of $1,750,000 as part of the final two stages to the amended December 2019 disposition agreement, consisting of a 0.6875% asset disposition on January 29, 2021, a 0.6875% asset disposition on April 27, 2021 and a 1.375% asset disposition on June 15, 2021.

On August 30, 2021, the Company entered into the Investment Agreement with a group of investors led by Anthony Marino, Michael Kaluza, Bradley Bennett, Jonathan Balkwill, Marty Proctor, and Mark Rollins which provided for, among other things: (i) a non-brokered private placement of units ("**Units**") of the Company ("**Non-Brokered Private Placement**") and a brokered private placement of subscription receipts ("**Subscription Receipts**") of the Company ("**Brokered Private Placement**" and together with the Non-Brokered Private Placement, the "**Private Placements**") for aggregate gross proceeds of $29.5 million; (ii) a reconstitution of the Board and appointment of a new management team (the "**Change of Management**"); and (iii) a change of the Company's name from "Altura Energy Inc." to "Tenaz Energy Corp." (collectively, the "**Reorganization**").

On September 22, 2021, the Company completed the Brokered Private Placement pursuant to which 136,112,000 Subscription Receipts were issued at a price of $0.18 per Subscription Receipt for gross proceeds of $24.5 million. The gross proceeds from the Brokered Private Placement were held in escrow pending completion of the Change of Management and the Non-Brokered Private Placement.

On October 8, 2021, the Company completed the Change of Management and the Non-Brokered Private Placement pursuant to which 27,778,000 Units were issued at a price of $0.18 per Unit for gross proceeds of $5.0 million. Each Unit was comprised of one Common Share and one warrant ("**Warrant**") of the Company, with each Warrant entitling the holder thereof to purchase one Common Share at a price of $0.18 per Common Share for a period of five years from the issuance date, subject to certain terms and conditions. One-third of the Warrants will vest and become exercisable upon the 20-day VWAP of the Common Shares (the "**Market Price**") equaling or exceeding $0.25 per Common Share, an additional one-third upon the Market Price equaling or exceeding $0.315 per Common Share and a final one-third upon the Market Price equaling or exceeding $0.36 per Common Share.

Immediately following the completion of the Change of Management and the Non-Brokered Private Placement, the Company issued 136,112,000 Common Shares pursuant to the conversion of the 136,112,000 Subscription Receipts previously issued by the Company in connection with the Brokered Private Placement, and $24.5 million in gross proceeds was released from escrow.

On October 15, 2021, the Company changed its name from “Altura Energy Inc.” to “Tenaz Energy Corp.” and the symbol for trading on the TSX Venture Exchange was changed to TNZ (formerly ATU).

On November 15, 2021, the Company announced a rights (“**Rights**”) offering (the “**Rights Offering**”) pursuant to which each shareholder of Common Shares on November 15, 2021 (the “**Record Date**”) received one (1) Right for each Common Share held by such shareholder. Each eight (8) Rights entitled the holder to subscribe for one Common Share upon payment of a subscription price of $0.18 per Common Share. The Common Shares commenced trading on the TSXV on an ex-rights basis at the opening of business on November 12, 2021. The Rights Offering expired at 4:00 p.m. (Calgary time) on December 13, 2021, after which time unexercised Rights were voided and of no value. Subscribers under the Private Placements agreed not to participate in the Rights Offering in respect of the securities subscribed for thereunder and having undertaken not to exercise, sell, trade or otherwise convey any interest in the Right Offering. Under the Rights Offering, holders of Rights purchased an aggregate of 10,179,840 Common Shares at a subscription price of $0.18 per Common Share for aggregate gross proceeds of approximately $1.8 million.

On December 17, 2021, the Company announced that it would proceed with the previously announced consolidation of its outstanding Common Shares (the “**Share Consolidation**”) on the basis of one new Common Share for every ten existing Common Shares (the “**Consolidation Ratio**”). The Consolidation Ratio was determined by the Company’s board of directors in accordance with the parameters authorized by the Company’s Shareholders at the special meeting of Shareholders held on October 7, 2021. Effective December 23, 2021, the Common Shares commenced trading on the TSXV on a post-consolidation basis.

The Company has a revolving operating demand loan (the “**Credit Facility**”) with a Canadian bank with a maximum borrowing limit of $4.0 million. As at December 31, 2021, bank debt was nil and the Company had outstanding letters of credit for $0.15 million.

Significant Acquisitions

The Company did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

DESCRIPTION OF THE BUSINESS

Tenaz is a public energy company focused on the acquisition and sustainable development of international oil and gas assets capable of returning free cash flow to Shareholders.

In addition, Tenaz conducts development of a semi-conventional oil project in the Rex member of the Upper Mannville group at Leduc-Woodbend in central Alberta.

While Tenaz believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration for, and development of, crude oil and natural gas has several inherent risks. See "*Risk Factors*" in this AIF.

Corporate Strategy

Following the Recapitalization Transaction, in addition to the continued development of the Company’s existing assets, the Company intends to target the acquisition of conventional and semi-conventional oil and gas assets in international markets. The Company will focus on building a portfolio of free cash flow assets that have the potential to provide returns to Shareholders through a growth-and-income capital markets model.

With the completion of the Private Placements, the Company believes it has established itself as a viable public vehicle for the acquisition of oil and gas producing assets. The Company will endeavor to identify, evaluate and acquire producing properties for which there is an opportunity for operational improvement and which have the potential to generate free cash flow and production growth. The Company recognizes the critical importance of sustainability in its environmental, social and governance practices, and will place a correspondingly high priority on performance and leadership in these areas. The Company is committed to the short and long-term environmental and economic sustainability of the jurisdictions in which it invests and the local communities in which it operates.

Personnel

As at December 31, 2021, the Company employed ten full-time employees located at the head office. The Company also retained six consultants, four of which are located at the head office and two of which are located in the field. In addition, the Company hires skilled contractors to perform drilling operations, well completions and other field service operations.

STATEMENT OF RESERVES DATA

The report on reserves data by McDaniel in Form 51-101F2 of NI 51-101 and the report of management and directors on reserves data and other information in Form 51-101F3 of NI 51-101 are attached as Appendix "A" and "B" to this AIF, respectively.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") was prepared by McDaniel, the Company's independent qualified reserves evaluator, with an effective date of December 31, 2021 and a preparation date of March 18, 2022. The Reserves Data summarizes the crude oil, NGLs and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs.

The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information, which the Company believes is important to readers of this AIF. McDaniel was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Tenaz's consolidated reserves are onshore in Canada and, specifically, in the Province of Alberta.

The McDaniel Report is based on certain factual data supplied by Tenaz and McDaniel'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 Tenaz to McDaniel. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

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 and well abandonment, decommissioning and reclamation costs.

Tenaz determined the future net revenue and present value of future net revenue after income tax expenses by utilizing McDaniel's before income tax future net revenue and the Company's estimate of income tax.

Tenaz's estimates of the after-income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of the Company's tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after-tax valuation. The after-tax net present value of Tenaz's crude oil and natural gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of the Company as a business entity, which may be significantly different. Tenaz's consolidated financial statements and management's discussion and analysis for the year ended December 31, 2021 should be consulted for additional information regarding the Company's taxes.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas reserves and the future cash flows attributed to such reserves. In general, such estimates are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGLs and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its consolidated reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by McDaniel 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 crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The information relating to the Company's consolidated crude oil, NGLs and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans, timing and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Note Regarding Forward-Looking Statements*", "*Industry Conditions*" and "*Risk Factors*".

In certain of the tables set forth below, the columns may not add due to rounding.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves

	Light Crude Oil & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids (3)	
Reserve Category	**Gross (1) Mbbl**	**Net (2) Mbbl**	**Gross (1) Mbbl**	**Net (2) Mbbl**	**Gross (1) MMcf**	**Net (2) MMcf**	**Gross (1) Mbbl**	**Net (2) Mbbl**
Proved								
Proved Developed Producing	150.5	121.3	599.4	516.3	5,119.8	4,601.0	120.9	100.7
Proved Developed Non-Producing	14.4	12.7	-	-	-	-	-	-
Proved Undeveloped	-	-	2,494.5	2,183.3	13,300.7	11,879.9	312.6	263.9
Total Proved	**164.9**	**134.0**	**3,093.9**	**2,699.6**	**18,420.5**	**16,480.9**	**433.5**	**364.6**
Total Probable	**45.2**	**36.7**	**2,148.8**	**1,834.2**	**12,451.1**	**11,097.2**	**292.8**	**237.9**
Total Proved + Probable	**210.1**	**170.7**	**5,242.7**	**4,533.8**	**30,871.7**	**27,578.1**	**726.3**	**602.5**

(1) Gross reserves are working interest reserves before royalty deductions.
(2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.
(3) Natural Gas Liquids include Condensate volumes.

Summary of Net Present Value of Future Net Revenue

Reserve Category	Before Income Taxes Discounted at 0% M$	5% M$	10% M$	15% M$	20% M$	After Income Taxes Discounted at 0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value Before Tax 10% (1) ($/BOE)
Proved											
Proved Developed Producing	22,807	23,496	22,776	21,685	20,564	22,807	23,496	22,776	21,685	20,564	15.13
Proved Developed Non-Producing	762	663	586	523	472	762	663	586	523	472	46.01
Proved Undeveloped	48,912	34,341	24,064	16,796	11,592	41,586	28,786	19,755	13,388	8,851	5.44
Total Proved (2)	**72,481**	**58,501**	**47,426**	**39,004**	**32,627**	**65,155**	**52,945**	**43,116**	**35,595**	**29,886**	**7.98**
Total Probable (2)	**79,360**	**54,660**	**39,211**	**29,232**	**22,547**	**61,440**	**41,872**	**29,715**	**21,952**	**16,821**	**9.91**
Total Proved + Probable (2)	**151,842**	**113,161**	**86,637**	**68,236**	**55,174**	**126,595**	**94,817**	**72,832**	**57,547**	**46,707**	**8.75**

(1) The unit values are based on net reserve volumes.
(2) Numbers may not add due to rounding.

Total Future Net Revenue (Undiscounted)

Reserve Category	Revenue (1) M$	Royalties (2) M$	Operating Costs M$	Develop-ment Costs M$	Abandon-ment & Reclama-tion Costs M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Total Proved	**300,402**	**37,585**	**106,883**	**72,999**	**10,454**	**72,482**	**7,327**	**65,155**
Total Proved + Probable	**514,274**	**67,415**	**180,488**	**102,559**	**11,970**	**151,842**	**25,247**	**126,595**

(1) Includes all product revenues and other revenues as forecast.
(2) Royalties include any net profits interests paid.

Future Net Revenue by Product Type

Reserve Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%) M$	Unit Value (1) $/Mcf, $/bbl
Total Proved Reserves	Light Crude Oil and Medium Crude Oil (Including Solution Gas and By-products)	3,237	24.15
	Heavy Crude Oil (Including Solution Gas and By-products)	44,189	16.37
	Total	**47,426**	
Total Proved + Probable Reserves	Light Crude Oil and Medium Crude Oil (Including Solution Gas and By-products)	3,866	22.64
	Heavy Crude Oil (Including Solution Gas and By-products)	82,772	18.26
	Total	**86,637**	

(1) Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.

Pricing Assumptions – Forecast Prices and Costs

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2021 in the McDaniel Report in estimating reserves data using forecast prices and costs. The forecast prices used are based on an average of the price decks of three independent engineering firms, GLJ Ltd., Sproule Associates Limited and McDaniel & Associates Consultants Ltd. (the "**Consultant Average Price Forecast**") at January 1, 2022, Benchmark weighted average historical prices for 2021 are also reflected in the tables below.

Summary of Price Forecasts
January 1, 2022

	Crude Oil Price Forecasts			Natural Gas Liquids Price Forecasts				Natural Gas Price Forecasts			
Year	WTI Crude Oil $US/bbl	Edmonton Light Crude Oil $C/bbl	Western Canadian Select Crude Oil $C/bbl	Edmonton Ethane $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Edmonton Cond. & Natural Gasolines $/bbl	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)						(4)		
History											
2011	95.10	95.05	77.10		55.15	76.50	104.20	4.00	3.70	2.90	1.010
2012	94.20	86.10	73.10		28.60	69.55	100.80	2.75	2.45	1.55	1.000
2013	97.95	93.05	75.25		38.90	69.40	104.65	3.75	3.20	0.95	0.970
2014	93.00	93.50	79.10		45.05	69.60	102.40	4.35	4.40	1.90	0.905
2015	48.80	57.75	44.80		6.60	36.50	60.30	2.60	2.80	1.10	0.785
2016	43.30	53.90	39.15		13.15	34.35	56.15	2.50	2.10	1.45	0.755
2017	50.90	62.85	50.70		28.90	44.60	66.85	3.00	2.40	1.60	0.770
2018	64.95	69.65	49.95		27.55	32.80	79.20	3.05	1.55	2.25	0.770
2019	57.00	69.00	58.70		17.40	23.55	70.30	2.55	1.60	2.00	0.755
2020	39.25	45.00	35.40		16.40	22.15	49.15	2.05	2.25	(0.10)	0.745
2021	67.95	80.25	68.80		43.10	51.15	85.45	3.90	3.55	1.35	0.800
Forecast											
2022	72.83	86.82	74.42	11.48	43.38	57.49	91.85	3.85	3.56	-	0.797
2023	68.78	80.73	69.17	10.33	35.92	50.17	85.53	3.44	3.21	2.30	0.797
2024	66.76	78.01	66.54	9.81	34.62	48.53	82.98	3.17	3.05	2.00	0.797
2025	68.09	79.57	67.87	10.01	35.31	49.50	84.63	3.24	3.11	2.00	0.797
2026	69.45	81.16	69.23	10.22	36.02	50.49	86.33	3.30	3.17	2.00	0.797
2027	70.84	82.78	70.61	10.42	36.74	51.50	88.05	3.37	3.23	2.00	0.797
2028	72.26	84.44	72.02	10.64	37.47	52.53	89.82	3.44	3.30	2.00	0.797
2029	73.70	86.13	73.46	10.86	38.22	53.58	91.61	3.50	3.36	2.00	0.797
2030	75.18	87.85	74.69	11.08	38.99	54.65	93.44	3.58	3.43	2.00	0.797
2031	76.68	89.61	76.19	11.31	39.77	55.74	95.32	3.65	3.50	2.00	0.797
2032	78.21	91.40	77.71	11.54	40.56	56.86	97.22	3.72	3.57	2.00	0.797
2033	79.78	93.23	79.27	11.77	41.37	57.99	99.17	3.79	3.64	2.00	0.797
2034	81.37	95.09	80.85	12.00	42.20	59.15	101.15	3.87	3.71	2.00	0.797
2035	83.00	96.99	82.47	12.24	43.05	60.34	103.17	3.95	3.79	2.00	0.797
2036	84.66	98.93	84.12	12.49	43.91	61.54	105.24	4.03	3.86	2.00	0.797
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.00	0.797

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.5% sulphur
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(3) Western Canadian Select at Hardisty, Alberta
(4) Historical prices based on AECO 7A (near month prices). 5A (daily price) expected to be equal to 7A over long term.
2021 historical prices: 7A $3.55/MMBTU, 5A $3.60/MMBTU

Weighted average historical prices Tenaz realized for the year ended December 31, 2021, were $69.23/bbl for heavy crude oil, $3.95/Mcf for natural gas and $50.87/bbl for NGLs.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the Company's gross reserves as at December 31, 2021, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Company's gross reserves as at December 31, 2020.

	Company Gross Reserves[(1)(2)] by Product Type[(3)]				
	Light Crude Oil & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Total Proved					
December 31, 2020	176.0	3,205.4	11,725.8	340.6	5,676.3
Extensions and improved recovery[(4)]	-	430.5	2,221.2	52.2	852.9
Technical Revisions[(5)]	17.6	(459.8)	4,457.1	41.5	342.1
Acquisitions	-	-	-	-	-
Dispositions[(6)]	(6.4)	(65.6)	(405.7)	(9.4)	(149.0)
Economic Factors	6.1	139.6	1,395.1	32.4	410.6
Production[(7)]	(28.4)	(156.2)	(973.0)	(23.8)	(370.5)
December 31, 2021[(3)]	**164.9**	**3,093.9**	**18,420.5**	**433.5**	**6,762.4**
Total Probable					
December 31, 2020	67.3	2,439.3	12,491.8	362.8	4,951.3
Extensions and improved recovery[(4)]	-	(97.2)	(329.0)	(7.7)	(159.7)
Technical Revisions[(5)]	(23.3)	(233.3)	(211.8)	(74.0)	(366.1)
Acquisitions	-	-	-	-	-
Dispositions[(6)]	(1.6)	(53.5)	(310.0)	(7.2)	(113.9)
Economic Factors	2.8	93.5	810.2	18.9	250.3
Production[(7)]	-	-	-	-	-
December 31, 2021[(3)]	**45.2**	**2,148.8**	**12,451.2**	**292.8**	**4,561.9**
Total Proved + Probable					
December 31, 2020	243.3	5,644.7	24,217.6	703.4	10,627.6
Extensions and improved recovery[(4)]	-	333.3	1,892.2	44.5	693.2
Technical Revisions[(5)]	(5.7)	(693.1)	4,245.3	(32.5)	(24.0)
Acquisitions	-	-	-	-	-
Dispositions[(6)]	(8.0)	(119.1)	(715.7)	(16.6)	(262.9)
Economic Factors	8.9	233.1	2,205.3	51.3	660.9
Production[(7)]	(28.4)	(156.2)	(973.0)	(23.8)	(370.5)
December 31, 2021[(3)]	**210.1**	**5,242.7**	**30,871.7**	**726.3**	**11,324.3**

Notes:

(1) Gross reserves are Company working interest reserves before royalty deductions.

(2) Based on the January 1, 2022 3 Consultant Average Price Forecast.

(3) Numbers may not add due to rounding.

(4) Extensions and Improved Recovery includes all new wells booked during the year at Leduc-Woodbend and a planned optimization within the Leduc-Woodbend Glauconitic Unit.

(5) Technical revisions were realized in all reserve categories. The revisions were driven by performance deviations from earlier estimates and higher than previously forecasted gas to oil ratios in the Leduc-Woodbend area.

(6) The dispositions amount relates to the 0.6875% asset disposition on January 29, 2021, the 0.6875% asset disposition on April 27, 2021 and the 1.375% asset disposition on June 15, 2021.

(7) Tenaz produced an average of 1,015 boe per day in 2021.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial years.

	Light Crude Oil & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2019	-	-	204.5	2,815.4	615.7	8,473.9	14.8	203.4
2020	-	-	-	2,559.0	-	8,034.0	-	233.0
2021	-	-	258.3	2,494.5	1,342.6	13,300.7	31.6	312.6

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. McDaniel has assigned 5,023.8 Mboe of proved undeveloped reserves in the McDaniel Report with $72.6 million of associated undiscounted capital, of which $24.2 million is forecast to be spent in the first two years.

The Company's proved undeveloped reserves are in its core area where Tenaz is actively employing capital to develop the Leduc-Woodbend property. As such, the Company expects that most of its booked undeveloped projects will be completed within a three-year time frame and that substantially all of its currently booked undeveloped projects will be completed within a four-year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors"* herein.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years.

	Light Crude Oil & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2019	111.1	111.1	316.9	1,990.1	1,635.3	10,019.7	32.7	233.9
2020	-	-	509.1	2,268.2	1,967.9	11,062.8	894.2	320.8
2021	-	-	75.0	1,965.8	549.6	10,882.9	12.9	255.7

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that the actual remaining quantities recovered will be greater or less than the proved and probable reserves. In most instances, probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. McDaniel has assigned 4,035.4 Mboe of probable undeveloped reserves in the McDaniel Report with $29.6 million of associated undiscounted capital, of which no capital is forecasted to be spent in the first two years.

The Company's probable undeveloped reserves are in its core area of Leduc-Woodbend. Tenaz is actively spending capital to develop the area. As such, the Company expects that substantially all of its currently booked undeveloped projects will be completed within a five-year time frame.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently 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 crude oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present value of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) timing and costs of future development activities; (vii) marketability of production; (viii) effects of government regulations; and (ix) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

While Tenaz does not anticipate any significant economic factors or significant uncertainties that will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, costs to abandon and reclaim properties, operating costs, royalty regimes and well performance that are beyond the Company’s control.

Abandonment, Decommissioning and Reclamation Costs

In connection with its operations, the Company will incur abandonment, decommissioning and reclamation ("**ADR**") costs for surface leases, wells, facilities and pipelines. Tenaz budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. Tenaz's overall ADR costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. The Company estimates such costs through a model that incorporates data from Tenaz's operating history, industry sources and cost formulas used by AER, together with other operating assumptions. The Company expects all of its net wells to incur these costs.

Tenaz anticipates the total amount of such costs, excluding inflation, to be approximately $5.6 million ($8.0 million including inflation) on an undiscounted basis, and approximately $2.2 million discounted at 10% and assuming an inflation rate of 2%, calculated in accordance with NI 51-101.

All existing and future ADR costs are reflected in McDaniel's estimate of future net revenue. The calculations of future net revenue associated with proved plus probable reserves under "Oil and Natural Gas Reserves" in this Annual Information Form include expenditures of approximately $4.0 million (on an undiscounted basis) and $0.4 million (discounted at 10%) in respect of the ADR of future wells and facilities where that obligation has not yet been incurred but is expected to be incurred.

Over the next two years, the Company does not anticipate any spending in respect of ADR costs.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the McDaniel Report of future net revenue attributable to the Company's proved reserves and proved plus probable reserves (using forecast prices and costs).

($000s)	Total Proved Reserves	Total Proved Plus Probable Reserves
2022	9,314	9,314
2023	15,268	15,268
2024	18,487	18,487
2025	23,263	23,263
2026	6,666	29,691
Thereafter	-	6,536
Total for all years undiscounted(1)	**72,999**	**102,559**
Total for all years discounted at 10% per year	**58,273**	**77,516**

Notes:
(1) Numbers may not add due to rounding.

Tenaz expects to use a combination of internally generated cash from operating activities, its Credit Facility and the issuance of new equity or debt where and when it believes appropriate to fund future development costs set out in the McDaniel Report. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all the reserves attributable in the McDaniel Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow.

Interest expense or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of any of the Company's properties uneconomic.

OTHER OIL AND NATURAL GAS INFORMATION

Principal Properties

Leduc-Woodbend

The Company has two producing properties in the Leduc-Woodbend area of central Alberta, located approximately 10 kilometers southwest of Leduc, Alberta. On January 29, 2021, April 27, 2021, and June 15, 2021 the Company divested of a 0.6875% working interest, a 0.6875% working interest and a 1.375% working interest, respectively, in the production, wells, lands and facilities as described in *"General Development of the Business"* of this AIF, in both producing assets.

Leduc-Woodbend Rex Pool

The majority of the Company's development and production activities in the Leduc-Woodbend area are directed towards 17° API heavy crude oil in the Rex member of the Upper Mannville Formation ("**Leduc-Woodbend**").

At December 31, 2021, Tenaz held a 85.7% working interest in 36,208 acres of land at Leduc-Woodbend, of which 16,584 net acres are undeveloped and 14,444 net acres are developed. Tenaz drilled three (2.63 net), completed four (3.52 net) and brought two (1.75 net) horizontal wells on production in 2021. McDaniel assigned 6,586.6 Mboe of proved reserves and 11,100.4 Mboe of proved plus probable reserves at Leduc-Woodbend in the McDaniel Report.

During the year ended December 31, 2021, Tenaz had average production of 932 boe/d (including 428 bbls/d of heavy crude oil, 64 bbls/d of NGLs and 2,637 Mcf/d of natural gas) from 17 producing wells. Production in the area is tied into two multi-well batteries and two single well batteries owned and operated by the Company. Crude oil sales volumes are trucked to multiple sales points and natural gas production is transported via pipeline and processed by two third-party operators.

Leduc-Woodbend Glauconitic D Unit No.1

The Company has a minor property in the Leduc-Woodbend area directed towards 33° API light crude oil in the *Glauconitic D Unit No.1* (the "**Glauc Unit**").

At December 31, 2021, Tenaz held a 52.4% working interest in 1,920 acres of land in the Glauc Unit, of which all 1,239 net acres are developed. McDaniel assigned 175.8 Mboe of proved reserves and 224.0 Mboe of proved plus probable reserves in the Glauc Unit in the McDaniel Report.

During the year ended December 31, 2021, Tenaz had average production of approximately 83 boe/d (including 78 bbls/d of light crude oil, one bbl/d of NGLs and 28 Mcf/d of natural gas) from seven producing wells. Production in the area is tied into a 52.4% working interest multi-well battery, operated by the Company. Light crude oil from the Glauc Unit is blended with heavy crude oil from the Leduc-Woodbend Rex Pool and is sold into the heavy crude oil stream. The blended crude oil sales volumes are trucked to multiple sales points and natural gas production is transported via pipeline and processed by a third-party operator.

Entice Area

The Entice area of southern Alberta is located approximately nine kilometers south of Strathmore, Alberta. On January 29, 2021, April 27, 2021, and June 15, 2021 the Company divested of a 0.6875% working interest, a 0.6875% working interest and a 1.375% working interest, respectively, in the area's lands as described in *"General Development of the Business"* of this AIF. At December 31, 2021, Tenaz held a 87.5% working interest in 7,175 acres of land in the Entice Area, of which 425 net acres are developed. McDaniel assigned no proved plus probable reserves in the Entice area in the McDaniel Report.

Oil and Natural Gas Wells

The following table sets forth the number and status of the Company's wells effective December 31, 2021.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada	30	23.4	35	23.0	-	-	1	0.9
Total	**30**	**23.4**	**35**	**23.0**	**-**	**-**	**1**	**0.9**

Notes:
(1) "Gross" wells means the number of wells in which the Company has a working interest.
(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Company's percentage working interest therein.

Properties With No Attributed Reserves

The following table summarizes, effective December 31, 2021, the gross and net acres of undeveloped properties in which the Company had an interest and also the number of net acres for which its rights to explore, develop or exploit are expected to expire within one year.

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Canada	25,804	22,437	4,200
Total	**25,804**	**22,437**	**4,200**

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Tenaz's properties with no attributed reserves. The Company will be required to make substantial capital expenditures in order to exploit, develop, prove and produce crude oil and natural gas from these properties in the future. If Tenaz's cash flow or Credit Facility are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Company. Failure to obtain such financing on a timely basis could cause Tenaz to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Tenaz to access sufficient capital for its exploration and development activities could have a material adverse effect on Tenaz's ability to execute its business strategy to develop these prospects.

The significant economic factors that affect Tenaz's development of its lands to which no reserves have been attributed are future commodity prices for crude oil and natural gas and Tenaz's outlook relating to such prices, and the future costs of drilling, completing, equipping, tie-in and operating the wells at the time that such activities are considered in the future.

The significant uncertainties that affect Tenaz's development of such lands are: (i) the future drilling and completion results Tenaz achieves in its development activities; (ii) drilling and completion results achieved by others on lands in proximity to Tenaz's lands; and (iii) future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Alternatively, uncertainty as to the timing and nature of the evolution or development of improved exploration drilling, completion and production technologies has the potential to accelerate development activities and enhance the economics relating to such lands.

Marketing

The Company’s financial results and condition are impacted primarily by the prices received for crude oil, NGLs and natural gas production. Crude oil, NGLs and natural gas have fluctuated widely and are determined by supply and demand factors, including available access to pipelines and markets, weather, general economic conditions in natural gas consuming and producing regions throughout North America and political factors. Any upward or downward movement in crude oil, NGLs and natural gas prices could have an effect on the Company's financial condition and capital development.

Tenaz's hedging transactions may include fixed price swaps, costless collars and put options to hedge a portion of its gross crude oil or natural gas production. To the extent that the Company engages in risk management activities related to commodity prices, it will be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of the Company's exposure to these entities.

At December 31, 2021, Tenaz held the following crude oil and natural gas contracts:

Period	Commodity	Type of Contract	Quantity	Pricing Point	Contract Price
Western Canadian Select (“WCS”) Swap Contracts					
Jan 1/22—Jan 31/22	Crude Oil	Fixed Swap	200 bbls/d	WCS	CAD $51.00
Feb 1/22—Feb 28/22	Crude Oil	Fixed Swap	200 bbls/d	WCS	CAD $59.70
Mar 1/22—Mar 31/22	Crude Oil	Fixed Swap	200 bbls/d	WCS	CAD $57.50
Apr 1/22—Apr 30/22	Crude Oil	Fixed Swap	175 bbls/d	WCS	CAD $65.75
May 1/22—May 31/22	Crude Oil	Fixed Swap	175 bbls/d	WCS	CAD $65.50
WCS Differential Swap Contracts					
Jan 1/22—Mar 31/22	Crude Oil	Fixed Swap	150 bbls/d	WCS-WTI Differential	CAD ($17.95)
Apr 1/22—Apr 30/22	Crude Oil	Fixed Swap	175 bbls/d	WCS-WTI Differential	CAD ($17.00)
May 1/22—May 31/22	Crude Oil	Fixed Swap	175 bbls/d	WCS-WTI Differential	CAD ($16.70)
WTI Put Options					
Jan 1/22—Mar 31/22	Crude Oil	Put Option(1)	150 bbls/d	WTI	CAD $62.00
Apr 1/22—Apr 30/22	Crude Oil	Put Option(2)	175 bbls/d	WTI	CAD $62.00
May 1/22—May 31/22	Crude Oil	Put Option(3)	175 bbls/d	WTI	CAD $62.00
Natural Gas Swap Contracts					
Jan 1/22—Jan 31/22	Natural Gas	Fixed Swap	1,000 GJ/d	AECO 5A	CAD $2.720
Feb 1/22—Feb 28/22	Natural Gas	Fixed Swap	1,000 GJ/d	AECO 5A	CAD $3.058
Mar 1/22—Mar 31/22	Natural Gas	Fixed Swap	1,000 GJ/d	AECO 5A	CAD $2.790
Apr 1/22—Apr 30/22	Natural Gas	Fixed Swap	1,000 GJ/d	AECO 5A	CAD $2.680
May 1/22—May 31/22	Natural Gas	Fixed Swap	1,000 GJ/d	AECO 5A	CAD $2.730

Notes:

(1) Includes a $19,000 liability to the counterparty on this contract for the deferred premium of $1.40 per barrel.
(2) Includes a $14,000 liability to the counterparty on this contract for the deferred premium of $2.65 per barrel.
(3) Includes a $14,000 liability to the counterparty on this contract for the deferred premium of $2.50 per barrel.

Tax Horizon

Based on McDaniel production forecasts, planned capital expenditures and the forecast commodity pricing employed in the McDaniel Report, the Company estimates that it will not be required to pay current income taxes until 2024.

Costs Incurred

The following table summarizes capital expenditures, excluding property dispositions, incurred by the Company during the year ended December 31, 2021.

	Property Acquisitions			
(M$)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**
Total	**-**	**-**	**80**	**10,311**

Drilling Activity

The following table sets forth the gross and net exploratory and development wells drilled by the Company during the year ended December 31, 2021. All wells were drilled in Canada.

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Crude Oil	-	-	3	2.63
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	**-**	**-**	**3**	**2.63**

Planned Capital Expenditures

The board of directors of the Company approved a capital budget of $7.8 million for 2022, funded with cash on its balance sheet. The budget included drilling two (1.75 net) Rex wells and completing four (3.50 net) Rex wells at Leduc-Woodbend. On March 24, 2022, the Company updated its guidance for 2022 and decreased planned capital expenditures to $5.8 million as the Company accelerated two (1.75 net) well completions into 2021 that were previously planned for the first quarter of 2022.

Production Estimates

The following table discloses for each product type the total volume of production estimated by McDaniel in the McDaniel Report for 2022 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light Crude Oil & Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Proved					
Proved Developed Producing	67	502	2,990	70	1,138
Proved Developed Non-Producing	8	-	-	-	8
Proved Undeveloped	-	219	312	7	279
Total Proved	**75**	**721**	**3,302**	**77**	**1,424**
Total Probable	**1**	**67**	**137**	**3**	**95**
Total Proved + Probable	**76**	**788**	**3,439**	**81**	**1,519**

The estimated production volumes for the Leduc-Woodbend Rex Pool, which accounts for 95% of McDaniel's total forecast production for the year ending December 31, 2022, is set forth below.

	Leduc-Woodbend Rex Pool Total Oil Equivalent (boe/d)
Proved	
Proved Developed Producing	1,066
Proved Developed Non-Producing	-
Proved Undeveloped	279
Total Proved	**1,345**
Total Probable	**93**
Total Proved + Probable	**1,438**

Production History

The following table summarizes certain information in respect of the Company's production, product prices received, royalties paid, operating expenses, transportation expenses and resulting netback for the periods indicated below.

	Quarter Ended 2021				Year Ended Dec. 31, 2021
	Mar. 31	**Jun. 30**	**Sep. 30**	**Dec. 31**	
Average Daily Production[1]					
Heavy Crude Oil[2] (bbls/d)	496	528	496	502	506
NGLs (bbls/d)	53	57	72	78	65
Conventional Natural Gas (Mcf/d)	2,356	2,543	2,861	2,895	2,666
Combined (boe/d)	942	1,009	1,045	1,063	1,015
Average Prices Received					
Heavy Crude Oil[2] ($/bbl)	56.92	66.71	72.81	80.20	69.23
NGLs ($/bbl)	41.50	44.4	56.23	56.78	50.87
Conventional Natural Gas ($/Mcf)	3.30	3.39	3.87	5.04	3.95
Combined ($/boe)	40.59	45.97	49.04	55.78	48.12
Royalties Paid					
Heavy Crude Oil[2] ($/bbl)	6.93	7.78	9.33	10.26	8.57
NGLs ($/bbl)	0.49	0.65	0.69	0.70	0.64
Conventional Natural Gas ($/Mcf)	0.14	0.18	0.15	0.32	0.20
Combined ($/boe)	4.45	5.15	5.53	7.10	5.60
Operating Expenses[3]					
Heavy Crude Oil[2] ($/bbl)	13.15	13.93	14.45	12.19	13.43
NGLs ($/bbl)	13.15	13.93	14.45	12.19	13.43
Conventional Natural Gas ($/Mcf)	2.19	2.32	2.41	2.03	2.24
Combined ($/boe)	13.15	13.93	14.44	12.20	13.43
Transportation Expenses					
Heavy Crude Oil[2] ($/bbl)	2.96	3.93	2.64	2.88	3.11
NGLs ($/bbl)	0.80	0.99	0.86	0.89	0.89
Conventional Natural Gas ($/Mcf)	0.14	0.14	0.16	0.14	0.14
Combined ($/boe)	1.96	2.45	1.75	1.81	1.99
Netback Received[4]					
Heavy Crude Oil[2] ($/bbl)	33.88	41.07	46.39	54.87	44.12
NGLs ($/bbl)	27.06	28.88	40.23	43.00	35.91
Conventional Natural Gas ($/Mcf)	0.83	0.75	1.15	2.55	1.37
Combined ($/boe)	21.03	24.44	27.32	34.67	27.10

Notes:
(1) Before the deduction of royalties.
(2) Light crude oil from Tenaz's Glauconitic Unit is blended with heavy crude oil from the Leduc-Woodbend Rex Pool and is sold into the heavy crude oil stream.
(3) The Company does not record operating expenses on a commodity basis. Information in respect of operating expenses for heavy crude oil and NGLs ($/bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a relative volume of heavy crude oil, NGLs and natural gas production basis.
(4) Netback is calculated by subtracting royalties, operating expenses and transportation expenses from prices received. See "Non-GAAP Measures".

Production Volume by Field

The following table indicates the average daily net production from Tenaz's properties for the year ended December 31, 2021.

	Light Crude Oil & Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Natural Gas Liquids (bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (boe/d)	Percentage (%)
Leduc-Woodbend Rex Pool	-	428	64	2,638	932	92
Leduc-Woodbend Glauconitic Unit(1)	-	78	1	28	83	8
Total	-	506	65	2,666	1,015	100

Notes:
(1) Tenaz's Glauconitic Unit produces light crude oil that is blended with heavy crude oil from the Leduc-Woodbend Rex Pool and is sold into the heavy crude oil stream.

Health, Safety, Environmental and Social Policies

The Company's *Code of Business Conduct and Ethics* policy and *Corporate Social Responsibility Policy* guide Tenaz's commitment to operating in a responsible manner. In 2020, the Company established an Environmental, Social and Governance committee and published its first sustainability report detailing its efforts and performance in health and safety, environmental management, and business and governance. These policies and the 2021 and 2020 sustainability reports are available on Tenaz's website at www.tenazenergy.com.

Tenaz's management, employees, consultants and all contractors are responsible and accountable for the overall health, safety and environmental program of the Company. Tenaz operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

Tenaz maintains a safe and environmentally responsible workplace and provides training, equipment and procedures to all individuals in adhering to its policies. It also solicits and takes into consideration input from neighbors, communities and other stakeholders in regard to protecting people and the environment.

The Company has an *Emergency Response Plan* (the "**ERP**") which is prepared in accordance with applicable regulations. The ERP is designed to provide the policies, practices and procedures to be implemented in the event of an emergency situation that arises at or as a result of Tenaz's operations, including but not limited to: a serious injury or fatality, fire or explosion, uncontrolled or hazardous product release and oil or hazardous chemical spill. The purpose of the ERP is to protect the health, safety and welfare of the public and workers and minimize the potential adverse environmental effects. On an annual basis, Tenaz holds a functional tabletop ERP exercise in Alberta to test its understanding and effectiveness in the case of an actual emergency. In addition, Tenaz holds exercises annually to ensure that its staff and executives are trained to respond to an emergency situation.

DIRECTORS AND EXECUTIVE OFFICERS OF THE CORPORATION

Tenaz has a Board of Directors currently consisting of five individuals. The Board of Directors are nominated by the Company and elected annually by Shareholders by ordinary resolution, and hold office until the next annual general meeting of the Shareholders or until each director's successor is appointed or elected pursuant to the ABCA. The Company's officers are appointed by and serve at the discretion of the Board of Directors.

The name, municipality of residence and principal occupation during the last five years of each of the directors and executive officers of the Company are as follows:

Name and Municipality of Residence	Position Held with the Company	Date First Elected or Appointed
Anthony Marino Calgary, Alberta	President, Chief Executive Officer and Director	October 8, 2021
Michael Kaluza Calgary, Alberta	Chief Operating Officer	October 8, 2021
Bradley Bennett Calgary, Alberta	Chief Financial Officer	October 8, 2021
David Burghardt Calgary, Alberta	Senior Vice President, Canadian Business Unit	July 31, 2015
Jennifer Russel-Houston Calgary, Alberta	Vice President, Geoscience	October 8, 2021
Jonathan Balkwill Calgary, Alberta	Vice President, Business Development	October 8, 2021
Travis Stephenson Calgary, Alberta	Vice President, Engineering	July 31, 2015
Marty Proctor[(1)(2)] Calgary, Alberta	Director and Board Chair	October 8, 2021
Anna Alderson[(1 Chair)(3)] Calgary, Alberta	Director	October 8, 2021
John Chambers[(1)(2)(3 Chair)] Calgary, Alberta	Director	June 4, 2019
Mark Rollins[(2 Chair)(3)] Gryon, Vaud, Switzerland	Director	October 8, 2021

Notes:

(1) Member of the Audit Committee.
(2) Member of the Sustainability, HSE, and Reserves Committee.
(3) Member of the Governance and Human Resources Committee.

As at March 24, 2022, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 2,347,075 Common Shares, representing approximately 8.2% of the issued and outstanding Common Shares (including Warrants and Stock Options, up to 18.1% on a fully diluted basis).

Anthony Marino, President, Chief Executive Officer and Director

Anthony Marino serves as the President, Chief Executive Officer and a Director of Tenaz since the completed Change of Management in October 2021. Mr. Marino has more than 39 years of oil and gas industry experience with an extensive background in operations management, business development, and capital markets. Mr. Marino has been Chief Executive Officer for several Canadian oil and gas companies executing growth-and-income capital markets models. From 2016 to May 2020, he led Vermilion Energy Inc. ("**Vermilion**") as President and Chief Executive Officer, which produced over 100 Mboe/d in ten countries across North America, Europe and Australia. Before becoming Chief Executive Officer of Vermilion, he was Chief Operating Officer from 2012 to 2016. Prior to Vermilion, Mr. Marino was President and Chief Executive Officer of Baytex Energy Corp. ("**Baytex Energy**") and Dominion Exploration Canada Ltd.

Mr. Marino holds a Bachelor of Science degree in Petroleum Engineering from the University of Kansas, holds a Master of Business Administration from California State University at Bakersfield (Outstanding Graduate) and he holds the Chartered Financial Analyst designation.

Michael Kaluza, Chief Operating Officer

Michael Kaluza serves as the Chief Operating Officer of Tenaz since the completed Change of Management in October 2021. Mr. Kaluza has over 36 years of experience in oil and gas industry, including operations, strategic operational planning and growth strategies. Mr. Kaluza has held senior leadership positions with intermediate and junior oil and gas producers, focusing on free cash flow generation from existing assets while achieving material cost reductions and capital-efficient production growth on acquired assets. His roles have included Chief Operating Officer of Vermilion from 2016 to November 2020, Executive Vice President/Director of Vermilion's Canadian Business Unit from 2013 to 2016, Vice President of Corporate Development and Planning of Baytex Energy and Chief Operating Officer of Delphi Energy Corp.

Mr. Kaluza holds a Bachelor of Science (Honours) degree in Petroleum Engineering from Montana College of Mineral Science and Technology.

Bradley Bennett, Chief Financial Officer

Bradley Bennett serves as the Chief Financial Officer of Tenaz since the completed Change of Management in October 2021. Mr. Bennett has significant public company experience managing global treasury, risk management, insurance, assurance and financial reporting. He has successfully established regional offices for new country entries, raised funds in US High Yield markets and managed a $2.1 billion syndicated credit facility. Most recently, Mr. Bennett was Treasurer of Vermilion from 2016 to April 2021.

Mr. Bennett is a Chartered Professional Accountant (Alberta) and holds a Bachelor of Commerce degree in Accounting and Finance from the University of Northern British Columbia.

David Burghardt, Senior Vice President Canada Business Unit

David Burghardt serves as the Senior Vice President Canada Business Unit of Tenaz since the completed Change of Management in October 2021 and was the former President and Chief Executive Officer at Altura. Mr. Burghardt is a Professional Engineer with 35 years of multi-discipline domestic and international experience with a background in all industry functions, particularly asset exploitation, reservoir management and production engineering. Prior to forming Altura, he worked in Europe for eight years with Vermilion, most recently as the Managing Director of their French Business Unit. Mr. Burghardt's prior experience includes being Founder, President and Chief Executive Officer of Kerogen Petroleum, Managing Director International Engineering at Equatorial Energy (Indonesia) Inc. and Founder and Vice President Engineering for Bison Resources.

Mr. Burghardt holds a Bachelor of Science degree in Chemical Engineering from the University of Saskatchewan, is registered as a Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta ("**APEGA**") and holds an ICD.D designation from the Institute of Corporate Directors.

Jennifer Russel-Houston, Vice President Geoscience

Jennifer Russel-Houston serves as Vice President Geoscience of Tenaz since the completed Change of Management in October 2021. Dr. Russel-Houston has significant experience as a petroleum geologist and technical leader overseeing geoscience evaluations of assets and guiding the assessment of opportunities, most recently with Osum Oil Sands Corp. as Vice President Geoscience and Land from 2014 to June 2021. Prior to joining Osum in 2008, Dr. Russel-Houston worked for Shell on both onshore and offshore projects where she developed expertise in reservoir evaluations, thermal production geology, and leading technical teams.

Dr. Russel-Houston holds a Bachelor of Science (Honours) degree from Queen's University, a Bachelor of Education degree from the University of Ottawa, and a Doctorate in Earth Sciences from Dalhousie University. Dr. Russel-Houston was President of the Canadian Society of Petroleum Geologists in 2020 and is registered as a Professional Geologist with APEGA.

Jonathan Balkwill, Vice President Business Development

Jonathan Balkwill serves as Vice President Business Development of Tenaz since the completed Change of Management in October 2021. Mr. Balkwill brings a combination of global technical and commercial experience in asset development and acquisitions. He has led multidisciplinary asset teams in Canada and Australia and successfully transacted on over $2.5 billion of acquisitions globally. Most recently, Mr. Balkwill was with Vermilion as an Asset Team Lead and Senior Business Development Engineer from 2014 to December 2020.

Mr. Balkwill holds a Bachelor of Applied Science in Petroleum Engineering with distinction from the University of Regina, he holds the Chartered Financial Analyst designation and he is registered as a Professional Engineer with APEGA.

Travis Stephenson, Vice President Engineering

Travis Stephenson serves as Vice President Engineering of Tenaz since the completed Change of Management in October 2021 and was the former Vice President Engineering at Altura. Mr. Stephenson is a Professional Engineer with 22 years of engineering and management experience in the oil and gas industry. Prior to joining Altura in December 2014, Mr. Stephenson was the Vice President Engineering at Chinook Energy Inc. (originally named Storm Ventures International) ("**Chinook**") and Country Manager for Chinook's Tunisian assets managing its staff and helping bring new technologies to Tunisia such as horizontal wells and multi-stage hydraulic fracture completions.

Mr. Stephenson holds a Bachelor of Science degree in Mechanical Engineering from the University of Saskatchewan and is registered as a Professional Engineer with APEGA.

Marty Proctor, Director and Board Chair

Mr. Proctor became the Chair of the Tenaz Board of Directors following the Change of Management in October 2021. Mr. Proctor is a seasoned energy executive with more than 35 years' experience in Canada and other international markets. Mr. Proctor is the Vice Chair of ARC Resources Ltd.'s ("**ARC**") Board of Directors and Director of GreenFirst Forest Products Inc. Prior to its merger with ARC in April 2021, Mr. Proctor was the President and Chief Executive Officer of Seven Generations Energy Ltd. ("**7G**") since 2017, the President and Chief Operating Officer of 7G from May 2014 to mid-2017 and the Chief Operating Officer of Baytex Energy from 2009 to 2014.

Mr. Proctor holds Bachelor of Science and Master of Science degrees in Petroleum Engineering from the University of Alberta, earned the ICD.D designation from the Institute of Corporate Directors, and is registered as a Professional Engineer with APEGA.

Anna Alderson, Director

Ms. Alderson joined the Tenaz Board of Directors following the Change of Management in October 2021. Ms. Alderson served as an Audit Partner with KPMG prior to her retirement in 2019 following a 36-year career. She has extensive experience providing audit and other services to domestic and international oil and gas companies. She is a Director of YMCA Calgary since 2017 and Past Chair of its Audit and Investment Committee. Ms. Alderson is also a member of the Audit Committees for both the Calgary Stampede and Calgary Foundation since April 2021.

Ms. Alderson is a Chartered Professional Accountant (Alberta), holds a Bachelor of Commerce degree in Accounting from the University of Saskatchewan and holds an ICD.D designation from the Institute of Corporate Directors.

John Chambers, Director

Mr. Chambers is a continuing Altura Board Member following the Change of Management in October 2021. Mr. Chambers is an independent businessman since November 2018 and has over 29 years experience in energy capital markets and merger and acquisition advisory. He is the Chairman of Westside Capital Inc., a Director of Sun God Resources Inc., a Director of Infra Fund IAL and sits on the Advisory Board of BlueX Energy Corp. Previously, Mr. Chambers was Vice-Chairman and President of GMP FirstEnergy from 2016 to 2018, the President and then Chief Executive Officer of FirstEnergy Capital Corp. from 2006 to 2016 and a former Chair of the Investment Industry Association of Canada.

Mr. Chambers holds a Master of Business Administration in International Finance from McGill University, holds a Bachelor of Science in Geophysics from the University of British Columbia and holds an ICD.D designation from the Institute of Corporate Directors.

Mark Rollins, Director

Mr. Rollins joined the Tenaz Board of Directors following the Change of Management in October 2021. Mr. Rollins' career spans more than 33 years in the oil and gas industry including senior leadership positions across international markets, midstream and downstream oil and gas and deregulated utility sectors with a proven commercial track record with extensive experience in business development, government negotiation and private equity. He is the Non-Executive Chairman of Advance Energy plc (United Kingdom) since February 2020 and a Non-Executive Director of Roquefort Therapeutics plc (United Kingdom) since March 2021. From 2015 to May 2019, he was the Chief Executive Officer and Chairman of the Executive Board of Ukrnafta, a publicly-listed company responsible for a significant proportion of oil production in Ukraine, and from 2008 to 2015 he was a Senior Vice President of BG Group plc (United Kingdom).

Mr. Rollins holds a Doctorate in Engineering Science from the University of Oxford as well as a Masters in Mathematics from the University of Cambridge.

Bankruptcies and Cease Trade Orders

To the knowledge of management of the Company, no director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Company is, as of the date of this AIF, or has been, within the last 10 years, been a director or executive officer of any company (including the Company) that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person.

Penalties or Sanctions

To the knowledge of management of the Company, no director, executive officer or Shareholder holding a sufficient number of securities to affect materially the control of the Company, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

To the knowledge of management of the Company, no director, executive officer or Shareholder holding a sufficient number of securities to affect materially the control of the Company, or a personal holding company of any such persons, has, within the 10 years preceding the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

Conflicts of Interest

Some of the directors and officers of Tenaz are also engaged in and will continue to engage in other activities in the oil and natural gas industry and, as a result of these and other activities, the directors and officers of Tenaz may become subject to conflicts of interest. 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 under the ABCA. No assurances can be given that opportunities identified by such Board members in the context of their relationship with another corporation will be provided to the Company. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at the date hereof, Tenaz is not aware of any existing or potential material conflicts of interest between Tenaz and a director or officer of Tenaz.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or officer of the Company, nor any other insider of the Company, nor their associates or affiliates has or has had, at any time within the three most recently completed financial years ending December 31, 2021, any material interest, direct or indirect, in any transaction or proposed transaction that has materially affected or would materially affect the Company other than in respect of the Change of Management and their participation in the Non-Brokered Private Placement. See "*General Developments of the Business – 3-Year History – 2021*".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was the subject of, during the Company's most recent financial year, nor are any such legal proceedings known to the Company to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Company.

There are no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2021; (ii) other penalties or sanctions imposed by a court or regulatory body against the Company that it believes would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements entered into by the Company with a court relating to securities legislation or with a securities regulatory authority during the financial year ended December 31, 2021.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

Tenaz has established an audit committee (the "**Audit Committee**") to assist the Board of Directors in carrying out its oversight responsibilities with respect to, among other things, financial reporting, internal controls, and the external audit process of the Company. The Terms of Reference for the Audit Committee are set out in Appendix “C” to this AIF.

Composition of the Audit Committee

The Audit Committee is comprised of three members: Anna Alderson (Chair), Marty Proctor and John Chambers each of whom is considered “independent” and “financially literate” in accordance with National Instrument 52-110 – *Audit Committees*. Each of the members of the Audit Committee has identified themselves as financial experts due to their relevant education and experience. Their backgrounds and qualifications which are relevant to their service on the Audit Committee are listed above – see “*Management of the Corporation – Directors and Officers – Biographies*”.

External Auditor Service Fees

The Audit Committee shall review and pre-approve all audit and non-audit services to be provided to Tenaz by its external auditor.

The following table discloses fees billed to the Company for the last two fiscal years by the Company's independent auditors:

	Year ended December 31, 2021 ($)	**Year ended December 31, 2020 ($)**
Audit fees(1)	132,145	130,225
Audit-related fees(2)	-	-
Tax fees(3)	7,000	7,000
All other fees	16,050	-
Total	**155,195**	**137,225**

Notes:

(1) Audit fees include costs of professional services rendered by KPMG for the audit of the Company’s annual financial statements, and the review of the Company’s interim financial statements.

(2) Represents the aggregate fees incurred in each of the last two fiscal years by the Company for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements (and not reported under the heading "Audit Fees").

(3) Tax fees consist of fees in respect of services provided in connection with tax compliance relating to the Company’s federal and provincial income tax returns, tax advice and tax planning.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Company includes an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series.

Effective December 23, 2021, the Company completed the Share Consolidation on the basis of one new Common Share for every ten existing Common Shares. The information below is presented on a post-consolidation basis.

As at March 24, 2022, 28,458,074 Common Shares are issued and outstanding as fully paid and non-assessable and no preferred shares were issued or outstanding. In addition, the Company has 2,010,500 Stock Options and 2,778,000 Warrants to purchase 4,788,500 Common Shares outstanding as of March 24, 2022.

The following is a summary of the rights, privileges, restrictions and conditions that attach to the Common Shares and a description of Stock Options and Warrants.

Common Shares

The Company is authorized to issue an unlimited number of Common Shares. The holders of Common Shares are entitled to one vote per Common Share at Shareholder meetings, to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of the Company upon its dissolution or winding up, subject to the rights of shares having priority over the Common Shares.

Effective December 23, 2021, the Company completed the Share Consolidation on the basis of one new Common Share for every ten existing Common Shares.

Stock Options

The Company has a stock option plan for directors, employees and service providers. Under the plan, Stock Options may be granted to purchase up to 10% of the outstanding shares of Tenaz and the maximum term of Stock Options granted is five years. The Board of Directors determines the vesting schedule at the time of grant. Unless otherwise determined by the Board of Directors at the time of grant, options vest as to one-third on each of the first, second and third anniversary dates of the date of grant.

See Tenaz's annual consolidated financial statements as at and for the year ended December 31, 2021 (a copy of which is available on SEDAR at www.sedar.com under Tenaz's SEDAR profile) for further details regarding the amount and value of Stock Options granted.

Warrants

Pursuant to the Change of Management and the Non-Brokered Private Placement on October 8, 2021, the Company issued Units, each Unit comprising of one Common Share and one Warrant of the Company with each Warrant entitling the holder thereof to purchase one Common Share at a price of $1.80 per Common Share (on a post-consolidation basis) for a period of five years from the issuance date, subject to certain terms and conditions.

See Tenaz's annual consolidated financial statements as at and for the year ended December 31, 2021 (a copy of which is available on SEDAR at www.sedar.com under Tenaz's SEDAR profile) for further details regarding the Company's issued and outstanding Warrants.

DIVIDENDS AND DISTRIBUTIONS

The Company has not declared nor paid any dividends on its Common Shares. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Company's earnings, financial requirements and other conditions existing at such future time.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSXV under the symbol "TNZ". The following table sets forth the price range and trading volume of these securities on a post-consolidation basis following the Share Consolidation on December 23, 2021 as reported by the TSXV for the period January 1, 2021 to March 18, 2022.

Month	High ($)	Low ($)	Volume
2021			
January	1.70	1.25	39,160
February	2.25	1.35	162,319
March	2.60	1.75	100,722
April	2.15	1.45	171,618
May	2.15	1.60	144,479
June	2.30	1.80	177,546
July	2.55	2.00	185,404
August	2.15	1.40	695,150
September	3.05	1.85	1,214,072
October	3.80	2.85	1,272,315
November	3.50	2.50	452,458
December	3.38	2.35	278,443
2022			
January	3.23	2.27	475,135
February	2.79	2.06	287,235
March (1-18)	2.74	2.18	363,041

INDUSTRY CONDITIONS

Production and Operation Regulations

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect Tenaz's operations in a manner materially different than they would affect other oil and gas entities of similar size. All current legislation is a matter of public record, and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Western Canada.

Pricing and Marketing

Crude Oil

In Canada, producers of oil negotiate sales contracts directly with crude oil purchasers. Crude oil prices are primarily based on worldwide and North American supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance.

In 2020, worldwide oversupply of crude oil, a lack of available storage capacity and decreased demand due to COVID-19 had a significant impact on the pricing of crude oil. In an effort to stabilize global oil markets, OPEX and a number of other oil producing countries announced an agreement to cut crude oil production by approximately 10 million bbl/d in April 2020, which was amended and adjusted throughout 2020 and early 2021. This agreement contributed to rebalancing global oil markets by achieving approximately 99.5% compliance with the agreed upon production adjustment commitments. The crude oil and gas industry has rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. In mid-2021 OPEC agreed to gradually reinstate crude oil production levels during the remainder of 2021 and in 2022.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tensions in Eastern Europe. In February 2022, Russia launched a large scale invasion of Ukraine. Ongoing military conflict between Russia and Ukraine have the potential to threaten the supply of oil and gas from the region. The long-term impacts of the conflict between these nations remains uncertain.

Natural Gas

Negotiation between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply and demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane, propane and pentane plus sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply and demand balance and other contractual terms.

Exports from Canada

In 2019, the National Energy Board (the "**NEB**") was replaced with the Canadian Energy Regulator (the "**CER**"). The CER's governing legislation is the Canadian Energy Regulator Act ("**CERA**") and the Impact Assessment Act (the "IAA"). The CER assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada.

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation (the Part VI Regulation)* until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas (other than NGL) not exceeding 30,000 m3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the CER and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

A major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints, Pipeline Capacity and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines will require a federal regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects.

The Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, was in service from October 1, 2021 and is expected to transport 760 Mboe/d at full capacity.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and it is expected to be in-service in 2023.

On June 9, 2021, TC Energy Corporation terminated the Keystone XL Pipeline project.

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban effectively prevents pipelines being built to, and export terminals being located on, the coast of British Columbia at any point north of Vancouver Island.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

NOVA Gas Transmission Ltd. is progressing construction activities on its system expansion project. Different aspects of that project came online throughout 2021 and all components are expected to be completed in 2022.

Construction activities on the Coastal GasLink Pipeline is progressing and is slated to be completed in 2023.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

The Canada-United States-Mexico Agreement and The North American Free Trade Agreement

On July 1, 2020, the Canada-United States-Mexico Agreement ("**CUSMA**") came into force replacing the North American Free Trade Agreement ("**NAFTA**").

Relevant to the energy industry, CUSMA does not contain the proportionality rules found in NAFTA's Article 605 whereby Canada remained free to restrict exports to the U.S. or Mexico provided that such export restrictions did not: (i) reduce the proportion of the energy resource exported relative to the total supply of that energy resource in Canada as compared to the proportion prevailing in the most recent 36-month period, (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply.

CUSMA also eliminates certain tariffs on some diluents used to transport heavy oil from Canada to the U.S. There has been little to no effect on Canada's energy industry by the ratification of CUSMA and the Company has not experienced any significant change to its operations or marketing activities as a result of the ratification of CUSMA.

Extractive Sector Transparency Measures Act

On June 1, 2015, the federal *Extractive Sector Transparency Measures Act* ("**ESTMA**") came into effect. This federal legislation imposes mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", which includes exploration, extraction and holding permits to do so. All companies subject to ESTMA are required to report payments over $100,000 made to any level of a Canadian or foreign government, including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments. These categories are separate; therefore, even if the aggregate of payments across the categories are greater than $100,000, one or more individual categories must reach the threshold for the report to be required. Any persons or entities found in violation of ESTMA (which includes making a false report, failing to make the report public or failing to maintain records for the prescribed period) can be fined up to $250,000 for each day that the offence continues.

Land Tenure

Where mineral rights are owned by the government, rights are granted to energy companies to explore for and produce crude oil, bitumen and natural gas pursuant to leases, licenses, permits and regulations as legislated by the respective provincial and federal governments. Crown lease terms vary in length, usually from two to five years for oil and natural gas leases and usually 15 years for Alberta bitumen leases. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Lands subject to a Crown oil and natural gas lease are continued beyond their primary term by drilling a well. A lease is proven productive at the end of its primary term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease. The tenure only comes to an end when the holder can no longer prove the lands subject to the lease are capable of producing crude oil or natural gas.

Many jurisdictions in Canada, including the provinces of Alberta and Saskatchewan, have legislation in place for mineral rights reversion to the Crown where stratigraphic formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for nonproducing lands, having met certain criteria as laid out in the relevant legislation.

Crude oil and natural gas can also be privately owned (freehold) and rights to explore for and produce such crude oil and natural gas are granted by leases on such terms and conditions as may be negotiated between the landowner and the lessee.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act (Canada)*. Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. 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.

From time to time, the governments of the Western Canadian provinces have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. These programs reduce the amount of Crown royalties otherwise payable.

Alberta

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On January 1, 2017, Alberta adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") continues to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands, which remain subject to their pre-existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of zero to a cap of 40%.

The Old Framework also includes a natural gas royalty formula, which formula provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Alberta Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Freehold mineral taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4 percent of revenues reported from freehold mineral title properties. Freehold mineral taxes are in addition to any other negotiated royalty or other payment required to be paid to the owner of such freehold mineral rights.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. In addition to royalties, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of $3.50 per hectare.

Environmental Regulation and Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, state, territorial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced or used in association with oil and gas operations, as well as requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat and endangered species protection, and minimum setbacks of oil and gas activities from surface water bodies.

Provincial environmental legislation in the Province of Alberta for the oil and gas industry is, for the most part, set out in the *Environmental Protection and Enhancement Act*, the *Oil and Gas Conservation Act*, the *Pipeline Act*, the *Water Act* and the *Technology and Emissions Reductions Implementation Act, 2019*, which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance.

Environmental legislation also requires that wells and facility sites be constructed, 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, or in the suspension or revocation of necessary licenses and approvals. The Company may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Company to statutory strict liability in the event of an accidental spill or discharge from a well, pipeline or facility, meaning that fault on the part of the Company need not be established if such a spill or discharge is found to have occurred.

Abandonment, decommissioning and reclamation costs are estimated by taking into consideration the costs associated with decommissioning, abandonment, remediation and reclamation, all adjusted according to its working interest and discounted in accordance with NI 51-101. Decommissioning liability cost estimates are based on information published by the AER with respect to AER Licensee Liability Management Program in Alberta. The Company has procedures in place which may address various matters including: spill prevention, response, notification, reporting, remediation and reclamation; environmental monitoring; government inspections; surface equipment spacing requirements; facility protection/security; vegetation management; surface water run-off/run-on management; groundwater; noise control; atmospheric emissions;

wellsite reclamation; earthen pits; storage tanks; naturally occurring radioactive materials; disposal wells; suspended or shut-in wells; waste management; and communications.

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 third parties or regulators or result in the suspension or revocation of regulatory approvals and may require the Company to incur costs to remedy such a discharge in an event not covered by the Company's insurance, which insurance is in line with industry practice. Furthermore, the industry expects incremental future costs associated with compliance with increasingly complex environmental protection requirements 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.

Climate Change Regulation and Greenhouse Gas Emissions

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently 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 Company's operations and cash flow. The Company's internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding.

Carbon Policy

In November 2015, Canada participated in the twenty first session of the Conference of the Parties of the United Nations Framework Convention on Climate Change ("**COP 21**") in Paris, France, the goal of which was to reach a new agreement for fighting global climate change. COP 21 resulted in the adoption of the Paris Agreement which made several recommendations, including: (i) holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above preindustrial levels, recognizing that this would significantly reduce the risks and impacts of climate change; (ii) increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production; and (iii) making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development. The Paris Agreement came into force on November 4, 2016.

Over the last several years, the federal government has undertaken a number of initiatives to achieve domestic GHG reductions that align with its commitments made under the Paris Agreement. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs intended to directly and indirectly reduce GHG emissions.

On June 21, 2018, the Government of Canada brought into force a pan-Canadian approach to the pricing of GHG emissions under the *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**"). The federal carbon pollution pricing system has two parts: (i) an emission reduction and trading system for large industry, known as the output-based pricing system; and (ii) a regulatory charge on 21 types of fuel, commonly known as the carbon tax. Each province was given the choice to either accept the federal requirement in full; create their own carbon pricing policies that meet federal standards; or a hybrid approach. Both Saskatchewan and Alberta have opted for the hybrid approach, where they have committed to develop province specific output-based pricing systems but are subject to the federal carbon tax on fuel. The federal carbon tax is applied on a broad set of fuels at $40 per tonne of GHG emissions in 2021 and will increase to $50 per tonne in 2022 and then by $15 per tonne per year until it reaches $170 per tonne in 2030.

The federal government also has a GHG emission reporting requirement under the *Canadian Environmental Protection Act, 1999* (CEPA) whereby facilities that emitted 10,000 tonnes or more of GHGs per year must report their emissions to Environment and Climate Change Canada. The federal government has also released draft *Clean Fuel Regulations* which will set emission limits on a variety of liquid fuels, including gasoline and diesel.

On November 1, 2021, the federal government announced that it will implement a cap on oil and gas emissions commencing in 2025 and asked Canada's Net-Zero Advisory Board for advice on developing this specific 2025 limit and further emissions reductions limits every five years thereafter until 2050.

In Alberta, GHG emissions are regulated under the *Emissions Management and Climate Resilience Act* and the Technology Innovation and Emission Reduction ("**TIER**") program, which came into effect January 1, 2020. The TIER system is mandatory for large emitters, being those that emit 100,000 tonnes or more of GHGs per year, however, facilities with less than 100,000 tonnes per year can voluntarily opt into the system by aggregating two or more smaller facilities together. Registered facilities are required to reduce their emission intensity (tCO2e/boe) by 10% based on a historical benchmark. Companies may meet these required reductions through improvements to their operations; by purchasing and retiring Alberta-based emission reduction or offset credits; by contributing to the provincial TIER Compliance Fund; or by a combination of these actions. Any facility registered into the TIER system can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion.

Methane Policy

On June 29, 2016, Canada joined the United States and Mexico in agreeing to reduce methane emissions from the oil and gas sector by up to 45% by 2025 from 2014 levels by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016, Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible. The United States has since cancelled their participation in this initiative.

On January 1, 2020, the Canadian federal government implemented the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*.

The federal regulations that apply to methane in the upstream oil and gas sector aim to control methane emissions and also reduce the amount of volatile organic compounds released into the air. These regulations apply generally to facilities that handle significant volumes of gas (facilities that produce or receive a combined volume of 60,000 m3 of hydrocarbon gas or greater annually in any of the past five years). The regulations outline regulatory requirements for fugitive equipment leaks, venting from well completions, and compressors, which came into force on January 1, 2020, and requirements for facility production venting restrictions and venting limits for pneumatic equipment, which come into force on January 1, 2023.

Operators of upstream oil and gas facilities are required to: implement a leak detection and repair program to stop natural gas leaks three times per year on facilities that produce or receive a combined volume of 60,000 m3 of hydrocarbon gas or greater annually; complete annual measurements of emissions from natural gas compressor vents to ensure emissions are under the applicable limit; and eliminate venting from well completions involving hydraulic fracturing.

Beginning in 2023, operators of upstream oil and gas facilities will be required to: meet a venting limit of 15,000 m3 of gas per year at facilities that produce and/or receive more than 60,000 m3 of gas per year, and limit venting from pneumatic devices to a maximum threshold.

All upstream oil and gas facilities to which the federal regulations apply are required to register and to keep records in order to demonstrate compliance with the proposed regulations. Facility operators are also required to submit reports at the request of the federal Minister of Environment.

The federal regulations do not apply in provinces which the federal government deems to have equivalent methane reduction regulations. Alberta, Saskatchewan and British Columbia have each reached equivalency agreements with the federal government and currently operators in these provinces are subject to only the provincial methane reduction requirements.

In Alberta, new design specifications have been put in place by the AER for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards are also included in the regulatory requirements and will raise current standards for performance, monitoring, measurement and reporting. The AER has published directives requiring methane emission reductions commencing January 1, 2020.

Oil and gas producers' operations are subject to costs being incurred to comply with carbon taxes, GHG emission reduction requirements, including methane emission reductions, and to preform necessary monitoring, measurement, verification and reporting of GHG emissions.

On October 11, 2021, the Canadian federal government announced its support for the Global Methane Pledge, which aims to reduce global methane emissions by 30 percent below 2020 levels by 2030. In support of the Global Methane Pledge, Canada announced its commitment to developing a plan to reduce methane emissions across the broader Canadian economy and to reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030, and that these goals will be achieved through an approach that will include regulation.

Current and future environmental legislation will require reductions in emissions from its operations and result in increased capital and operational expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition and results of operations.

Liability Management Rating Programs

On July 30, 2020, the Government of Alberta announced a new Liability Management Rating Program (the "LMR Program") that overhauls and modernizes the current liability management program, known as the Liability Management Ratio ("**LMR**") which uses a licensee's ratio of deemed asset value to deemed liability value to determine the risk that the licensee poses to the Orphan Well Association and to determine if a security deposit is required to mitigate that risk. The LMR was replaced by Directive 088: Licensee Life-Cycle Management ("**LLCM**"), which directive was released and became effective on December 1, 2021. Unlike the LMR, which measures two metrics to determine a licensee's risk, the LLCM assesses more than 30 additional metrics, such as the licensee's financial capability, previous closure activity, operational performance and regulatory compliance. Additionally, the new liability framework includes an Inactive Inventory Reduction Program which introduced annual mandatory liability reduction spending targets for each licensee. The new framework announcement on July 30, 2021, also includes the development of a program to address legacy sites that were abandoned, remediated or reclaimed before current requirements were introduced.

Complementing the LMR Program and associated directives, Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes the Orphan Fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LMR Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be funded by licensees in the AB LMR Program who contribute to a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment, decommissioning and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences for large facilities. Collectively, these programs, the AB LMF, and associated directives are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In addition, to address abandonment, decommissioning and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment, decommissioning and reclamation operations though industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Tenaz. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with Tenaz's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business generally. Additional risks and uncertainties not currently known to the Company that it currently views as immaterial may also materially and adversely affect its business, financial condition and/or results of operations. Shareholders and potential Shareholders should carefully consider the information contained herein before deciding whether to purchase Common Shares, and, in particular, the following risk factors.

Market Risks

Volatility of crude oil and gas prices

The Company's reserves, financial performance, financial position, and cash flows are dependent on the prices received for crude oil and natural gas production. Crude oil and natural gas prices have fluctuated materially during recent years and are determined by supply and demand factors. Supply factors can include availability (or lack thereof) of transportation capacity and production curtailments by independent producers or by OPEC members. Demand factors can be impacted by general economic conditions, supply chain requirements, environmental and other factors. Environmental and other factors include changes in weather, weather patterns, fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, and technology advances in fuel economy and energy generation devices. Shifts in supply and demand for certain commodities, products, and services may occur as climate-related risks are increasingly taken into account.

Volatility of foreign exchange rates

The Company's reserves, financial performance, financial position, and cash flows may be affected by prevailing foreign exchange rates. An increase in the exchange rate for the Canadian dollar versus the U.S. dollar or other currencies may reduce the Canadian equivalent cash receipts for the Company's production. Conversely, a decrease in the exchange rate for the Canadian dollar versus the U.S. dollar or other currencies may increase the Canadian equivalent cash outflows for the Company's operating and capital expenditures.

Volatility of the Market Price of Common Shares

The market price of the Company's Common Shares may be volatile and this volatility may affect the ability of Shareholders to sell Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to: the Company's operating results or financial performance failing to meet the expectations of securities analysts or investors in any quarter; downward revision in securities analysts' estimates; governmental regulatory action; adverse change in general market conditions or economic trends; acquisitions, dispositions or other material public announcements by the Company or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*" in this AIF. In addition, the market price for securities in stock markets including Common Shares may experience significant price and trading fluctuations. These fluctuations may result in volatility in the market prices of securities that may be unrelated or disproportionate to changes in the Company's operating and financial performance.

Hedging Activities

The Company may enter into agreements to fix commodity prices, interest rates, and foreign exchange rates to offset the risks affecting the business. To the extent that the Company engages in price risk management activities to protect the Company from unfavourable fluctuations in prices and rates, the Company may also be prevented from realizing the full benefits of favourable fluctuations in prices and rates.

To the extent that risk management activities and hedging strategies are employed to address these risks, the Company would also be exposed to risks associated with such activities and strategies, including: counterparty risk, settlement risk, basis risk, liquidity risk and market risk. These risks could impact or negate any benefits of risk management activities and hedging strategies.

In addition, commodity hedging arrangements could expose the Company to the risk of financial loss if: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangements; or a sudden unexpected event materially impacts crude oil and natural gas prices.

Alternatives to, and Changing Demand for, Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Tenaz cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Operational Risks

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The Company's long-term commercial success depends on its ability to find, acquire, develop and commercially produce crude oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in reserves will depend on both the Company's ability to explore and develop existing properties and on the Company's ability to select and acquire suitable producing properties or prospects. There is no assurance that Tenaz will be able continue to find satisfactory properties to acquire or participate in. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of crude oil and natural gas.

Future crude oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including but not limited to hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to crude oil and natural gas wells, production facilities, other property and the environment or in personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Increase in costs or a decline in production level

The Company's financial performance, financial position, and cash flows are affected by the Company's operating costs and production levels. Operating costs may increase and production levels may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond the Company’s control.

The Company’s financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality standards and supply chain disruptions. Electricity, chemicals, supplies, abandonment, reclamation and labour costs are examples of operating costs that are susceptible to significant fluctuations. Fluctuations in operating and capital costs could negatively impact Tenaz’s business, financial condition, results of operations, cash flows and value of its crude oil and natural gas reserves.

Production levels may decline due to an inability for the Company to market crude oil and natural gas production. This could result from the availability, proximity and capacity of gathering systems, pipelines and processing facilities that the Company depends on in the jurisdictions in which it operates.

Operating costs could increase as a result of blowouts, environmental damage, unforeseen circumstances related to climate-change, and other unexpected and dangerous conditions which could result from a number of operating and natural hazards associated with the Company’s operations. In addition to higher costs, the Company may have a potential liability to regulators and third parties as a result. The Company maintains liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected operations, to the extent that such insurance is commercially viable. The Company may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons.

Seasonal Factors

The production of crude oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Weather Conditions

The Company’s operations may be impacted by changing weather conditions, which may include: changes in temperature extremes, changes in precipitation patterns (including drought and flooding), and increased severity of extreme weather events such as cyclones or floods. These events can impact the Company’s operations, causing shutdowns and increased costs.

Cost of New Technology

The crude oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other crude 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.

Title to and Right to Produce from Assets

Unforeseen title defects may result in a loss of entitlement to production and reserves. Although the Company conducts title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat the Company’s title to the purchased assets. If such a defect were to occur, the Company’s entitlement to the production from such purchased assets could be jeopardized and, as a result, return of capital to Shareholders may be reduced.

Expiration of Licenses and Leases

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

Insurance Risks

The Company’s property, liability and director and officer insurance are subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these or other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Company. Furthermore, the inability of the Company to obtain sufficient director and officer insurance may impact its ability to retain directors and (or) officers of the Company.

Regulatory and Political Risks

The Company is subject to extensive and complex regulations and laws enforced by various regulatory agencies.

Tax, Royalty, and other Government Legislation

Income tax laws, royalty and other government legislation relating to the oil and gas industry in the jurisdictions in which the Company operate may change in a manner that adversely affects the Company.

Government Regulations

The Company's operations are governed by various levels of governments. The Company is subject to laws and regulations regarding environment, health and safety issues, lease interests, taxes and royalties, among others. Failure to comply with the applicable laws can result in significant increases in costs, penalties and even losses of operating licenses. The regulatory process involved for each level of government is not uniform and regulatory regimes vary as to complexity, timeliness of access to, and response from, regulatory bodies and other matters specific to each level of government. If regulatory approvals or permits are delayed, not obtained, or revoked, there can also be delays or abandonment of projects, decreases in production and increases in costs, and the Company may not be able to fully execute its strategy. Governments may also amend or create new legislation and regulatory bodies may also amend regulations or impose additional requirements which could result in reduced production and increased capital, operating and compliance costs.

Policy and Legal Risks

Policy actions that attempt to constrain actions that contribute to the adverse effects of climate change or policy actions that seek to promote adaptation to climate change continue to evolve. Policy changes could include implementing carbon-pricing mechanisms to reduce GHG emissions, shifting energy-efficient solutions, and promoting more sustainable land-use practices. The risks and financial impact of policy changes depend on the nature and timing of the policy change.

The Company may be exposed to increased litigation risk relating to climate change. The oil and gas industry has seen an increase in climate-related litigation claims being brought before the courts by property owners, municipalities, and public interest organizations. Some of these claims include the failure of organizations to mitigate the impacts of climate change, failure to adapt to climate change, and the insufficiency of disclosure around material financial risks. As the value of loss and damage arising from climate change increases, litigation risk will also grow.

Political Events

Political events throughout the world that cause disruptions in the supply of crude oil and natural gas may affect the marketability and price of crude oil and natural gas acquired or discovered by the Company. Political developments arising in the jurisdictions in which the Company operates have a significant impact on the price of oil and natural gas.

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions

The Company's crude oil and natural gas properties, wells and facilities could be subject to natural disaster, a terrorist attack, civil unrest, pandemics and other disruptions. If any of the Company's properties, wells or facilities or any infrastructure on which the Company relies are the subject of such an event, such event may have a material adverse effect on the Company's financial performance, financial position, and cash flows.

Litigation

From time to time, the Company may be the subject of litigation and regulatory proceedings. Claims under such litigation or proceedings may be material. The types of claims the Corporation may face include, without limitation, claims for breach of contract, environmental damage, negligence, product liability, tax, patent infringement and employment matters. The outcome of any such litigation is not certain, but may materially impact the Company's financial condition or results of operations. The Company may also be subject to adverse publicity related to such claims, regardless whether the Company is ultimately found responsible. In addition, the Company may be required to incur significant expenses or devote significant resources, not covered by available insurance, defending any such litigation.

Indigenous Claims

The economic impact on the Company of claims of indigenous title is unknown. Indigenous peoples have claimed indigenous rights and title in portions of Western Canada. The Company is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Company's business and financial results.

Environmental Non-Governmental Organization Action

Environmental non-governmental organizations have become more aggressive in pursuing legal challenges to oil and gas companies, drilling and pipeline projects. In turn, this could result in increased costs and additional operating restrictions or delays.

Financing Risks

Additional Financing

The Company’s Credit Facility and any replacement credit facilities may not provide sufficient liquidity. The amounts available under the Company’s Credit Facility may not be sufficient for future operations, or the Company may not be able to obtain additional financing on attractive economic terms, if at all.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the Company's ability to make the necessary capital investments to maintain or expand its crude oil and natural gas reserves may be impaired. To the extent the Company is required to use cash flow to finance capital expenditures or property acquisitions, may impact the level of cash available.

Debt Service

The Company may finance a significant portion of its operations, future expansion and/or exploration and development activities through debt. Amounts paid in respect of interest and principal on debt incurred by the Company may impair its ability to satisfy its other obligations. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment by the Company of its debt obligations.

Lenders may be provided with security over substantially all of the assets of the Company. If the Company becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy or covenant breaches, a lender may be able to foreclose on or sell the assets of the Company.

Credit Facility

The current Credit Facility is subject to review on May 22, 2022 but may be set at an earlier or later date at the sole discretion of the Company's lender. There is a risk that the Credit Facility will not be renewed for the same amount or on the same terms. There can be no assurance that the amount will be adequate for the Company’s future financial obligations including its capital expenditure program, or that additional funds will be available under the Credit Facility or from other sources on terms acceptable to the Company.

The Company is required to comply with its covenants under the Credit Facility. In the event that the Company does not comply with its covenants under the Credit Facility, access to the Credit Facility could be restricted or accelerated repayment could be required by its lenders and debt service costs would likely increase. Although the Company believes it is in compliance with existing covenants, compliance may not be sustainable or covenants may become increasingly onerous.

Variations in Interest Rates

An increase in interest rates could result in an increase in the amount the Company pays to service debt.

Environmental Risks

Environmental Legislation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial, state and federal legislation. A breach of such legislation may result in the imposition of fines, the issuance of clean up orders in respect of the Company or its assets, or the loss or suspension of regulatory approvals. Such legislation may include carbon taxes, enhanced emissions reporting obligations, mandates on the equipment specifications, and emissions regulations. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Company. In addition, such legislation may inhibit the Company's ability to operate its assets and may make it more difficult for the Company to compete in the acquisition of new property rights. Presently, the Company does not believe the financial impact of these regulations on capital expenditures and earnings will be material. However, the Company actively monitors and assesses its exposure to this legislation.

The Company expects to incur abandonment, decommissioning and reclamation costs in the ordinary course of business as existing oil and gas properties are abandoned and reclaimed. These costs may materially differ from the Company's estimates due to changes in environmental regulations.

The Company's exploration and production facilities and other operations and activities emit some amount of greenhouse gases, which may be subject to legislation regulating emissions of greenhouse gases. This may result in a requirement to reduce emissions or emissions intensity from the Company's operations and facilities. It is possible that future regulations may require further reductions of emissions or emissions intensity.

Hydraulic Fracturing

Tenaz utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated completion fluids and other technologies in connection with its drilling and completion activities. Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate oil and natural gas production. Hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Hydraulic fracturing has featured prominently in recent political, media and activist commentary on the subject of water usage and environmental damage. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves, as well as increase costs.

With activist groups expressing concern about the impact of hydraulic fracturing on the environment and water supplies, the Company's corporate reputation may be negatively affected by the negative public perception and public protests against hydraulic fracturing. In addition, concerns regarding hydraulic fracturing may result in changes in regulations that delay the development of oil and natural gas resources and adversely affect the Company's costs of compliance and reputation. Changes in government may result in new or enhanced regulatory burdens in respect of hydraulic fracturing which could affect the Company's business.

Climate Change

In addition to other climate-related risks discussed elsewhere in this AIF, the Company faces transition risks and physical risks related to climate change.

Transition risks are risks that relate to the transition to a lower-carbon economy. Transition risks impact the volatility of crude oil and natural gas prices (as consumer demand for oil and gas may decrease); environmental legislation and hydraulic fracturing regulations (which may delay or restrict the development of oil and gas); the ability to obtain additional financing (as sources of financing for oil and gas development may become more restricted); and the reliance on key personnel, management, and labour (as the workforce may transition to other sources of energy development). Practices and disclosures relating to environmental matters, including climate change, are attracting increasing scrutiny by stakeholders. The Company's response to addressing environmental matters can impact the Company's reputation and affect the Company's ability to hire and retain employees; to compete for reserve acquisitions, exploration leases, licenses and concessions; and to receive regulatory approvals required to execute operating programs.

Physical risks relate to the physical impact of climate change, which can be event driven (acute) or longer-term shifts (chronic) in climate patterns. Physical risks can have financial implications for the Company, such as direct damage to assets and indirect impacts from production disruptions. Physical risks may also increase the Company's operating costs.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Climate Change Regulation – Carbon Policy*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Investment, Acquisition and Expansion Risks

Competition

The oil and gas industry is highly competitive. The Company competes for reserve acquisitions, exploration leases, licences, concessions, marketing of crude oil and natural gas and skilled industry personnel with a significant number of other oil and gas companies, some of which have significantly greater financial resources than Tenaz. The Company 's competitors include major integrated oil and natural gas companies, numerous junior and intermediate oil and gas companies as well as other independent oil and natural gas companies and individual producers and operators.

The Company's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Execution of Corporate Strategy, International Operations and Future Geographical/Industry Expansion

The Company's operations are currently focused on the development of a semi-conventional oil project in the Rex member of the Upper Mannville group at Leduc-Woodbend in central Alberta. Management's strategy and expertise are focused on the future acquisitions and sustainable development of international oil and gas assets capable of returning free cash flow to Shareholders in other geographical regions, including Europe, the Middle East and North Africa, and South America. In the future, the Company may acquire or move into new industry related activities, enter into new geographical areas, or acquire different energy related assets. These actions may result in unexpected risks or alternatively, significantly increase the Company's exposure to one or more existing risk factors.

Acquisition Assumptions

When making acquisitions, the Company estimates the future performance of the assets to be acquired. These estimates are subject to inherent risks associated with predicting the future performance of those assets. These estimates may not be realized over time. As such, assets acquired may not possess the value the Company attributes to them.

Third Party Credit Risk

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company intends to target the acquisition of conventional and semi-conventional oil and gas assets in international markets. The Company will focus on building a portfolio of free cash flow assets that have the potential to provide returns to Shareholders through a growth-and-income capital markets model.

In order to achieve the benefits of any future acquisitions, the Company will be dependent upon its ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Company. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during the process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect the Company's ability to achieve the anticipated benefits of such acquisitions.

Management continually assesses the value and contribution of individual properties and other assets. In this regard, non-core assets may periodically be disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could realize less than their carrying amount on the financial statements of the Company.

Dilution

Future acquisitions or financing or other transactions may involve the issuance of securities by the Company which may be dilutive.

Changing Investor Sentiment

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

Reserve Estimates

Reserves and estimated future net revenue to be derived from reserves are estimates and have been independently evaluated by McDaniel. The estimation of reserves is a complex process and requires significant judgment. Actual production and ultimate reserves will vary from those estimates and these variations may be material.

Assumptions incorporated into the estimation of reserves are based on information available when the estimate was prepared. These assumptions are subject to change and many are beyond the Company's control. These assumptions include: initial production rates; production decline rates; ultimate recovery of reserves; timing and amount of capital expenditures; marketability of production; future prices of crude oil and natural gas; operating costs; well abandonment costs; royalties, taxes, and other government levies that may be imposed over the producing life of the reserves.

In addition, estimates of reserves that may be developed and produced in the future are often based on methods other than actual production history, including: volumetric calculations, probabilistic methods, and upon analogy to similar types of reserves. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves. As such, reserve estimates may require revision based on actual production experience.

The present value of estimated future net revenue referred to in this AIF should not be construed as the fair market value of estimated crude oil and natural gas reserves attributable to the Company's properties. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations and taxation.

Other Risks

Information Technology and Cyber Security

The Company is 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. Although the Company has security measures and controls in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws and a disruption to its business activities. 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.

The Company relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Company is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data. In addition, information systems could be damaged or 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. 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, and confidential and proprietary information, and on the Company’s business, financial condition, results of operations and cash flows.

Management Estimates and Assumptions

In preparing consolidated financial statements in accordance with IFRS, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Company must exercise significant judgment. Estimates may be used in management’s assessment of items such as depreciation and accretion, fair values, useful life of assets, income taxes, stock-based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Company.

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 undertaken and will undertake 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 Canadian 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. Additionally, implementing and monitoring effective internal controls can be costly. 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 Common Shares.

Reliance on Key Personnel, Management and Labour

The Company’s success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect. The contributions of the Company’s existing management team to immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and the labour force in certain areas in which the Company operates may be limited. The Company expects that similar projects or expansions will proceed in the same area during the same time frame as the Company's projects. The Company's projects require experienced employees, and such competition may result in increases in compensation paid to such personnel or in a lack of qualified personnel. There can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of the Company's business and the execution of its strategy.

Potential Conflicts of Interest

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

The COVID-19 Pandemic

The COVID-19 pandemic, and initial actions taken in response, resulted in a significant contraction in the global economy. This caused a period of unprecedented disruption in the oil and gas industry and negatively impacted the demand for, and pricing of, energy products, including crude oil, NGLs and natural gas produced by the Company. A consequence of this disruption is that the oil and gas industry experienced a period of market contraction. Furthermore, the oil and gas industry experienced an increased risk of counterparty bankruptcy and insolvency. Although the pricing of energy products has returned to historical norms, volatility persists and disruptions to the oil and gas industry related to the pandemic could be severe.

In response to the COVID-19 pandemic, the Company has implemented additional health and safety protocols within its Calgary office and field operations and continues to make adjustments to its health and safety protocols as required.

There are many variables and uncertainties that still remain regarding COVID-19, as well as its continued impact on the economic environment, including the duration of any further disruption to the oil and gas industry. During the COVID-19 pandemic, inflation has been driven by many factors, including disruptions to local and global supply chain and transportation services. Inflation and disruptions to supply chain and transportation services have the potential to disrupt the Company's operations, projects and financial condition.

There may be further disruption in the demand for commodities which may have a prolonged adverse effect on the Company's financial condition, operations, income, results from operations and cash flows. Additionally, COVID-19 has the potential to directly affect the health of our employees, even in the face of our additional health and safety protocols. Other risks disclosed in this AIF may be heightened and there may also be effects that are not currently known as the full impact of the COVID-19 pandemic is still uncertain.

Forward-Looking Statements May Prove Inaccurate

Readers are cautioned not to place undue reliance on forward-looking information in this AIF. 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.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Company's Common Shares is Odyssey Trust Company at its principal office in Calgary, Alberta.

AUDITOR

The Company's auditor is KPMG LLP, Chartered Professional Accountants, 3100, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 2V7.

MATERIAL CONTRACTS

The Company has not entered into any material contracts outside its normal course of business.

INTERESTS OF EXPERTS

Reserve estimates contained in this AIF are derived from reserve reports prepared by McDaniel. As of the date hereof, McDaniel, as a group, does not beneficially own, directly or indirectly, any Common Shares.

KPMG LLP is the auditor of the Company and is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com under Tenaz's SEDAR profile.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, where applicable, are contained in the Company's information circular in respect of its most recent annual general meeting of Shareholders involving the election of directors. Additional financial information is provided in the Company's audited consolidated financial statements and management's discussion and analysis for the most recently completed financial year ended December 31, 2021.

APPENDIX "A"

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Tenaz Energy Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021 estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves 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 data are free of material misstatement. An evaluation also includes assessing whether the reserves 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 + 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, 2021, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	December 31, 2021	Canada	-	86,637	-	86,637

6. In our opinion, the reserves data respectively 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 data that we reviewed but did not audit or evaluate.

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

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed)

Michael J. Verney, P.Eng.

Executive Vice President

Calgary, Alberta, Canada

March 18, 2022

APPENDIX "B"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Tenaz Energy Corp. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in Appendix "A" to the Annual Information Form of the Company for the year ended December 31, 2021 (the "**AIF**").

The Sustainability, HSE, and Reserves Committee of the board of directors of the Company (the "**Board of Directors**") has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator, McDaniel & Associates Consultants Ltd. ("**McDaniel**");

(b) met with McDaniel to determine whether any restrictions affected the ability of McDaniel to report without reservation; and inquired whether there had been disputes between the previous independent qualified reserves evaluator and management; and

(c) reviewed the reserves data with management and with McDaniel.

The Sustainability, HSE, and Reserves Committee has reviewed the Company'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 Sustainability, HSE, and Reserves Committee, approved:

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

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

(c) the content and filing of this report.

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

(signed)	(signed)
Anthony Marino President and Chief Executive Officer	Michael Kaluza Chief Operating Officer
(signed)	(signed)
Mark Rollins Director	Marty Proctor Board Chair

March 24, 2022

APPENDIX "C"

Tenaz Energy Corp.
Terms of Reference for the Audit Committee

I. PURPOSE

The primary function of the Audit Committee (the "**Committee**") is to assist the Board of Directors (the "**Board**") of Tenaz Energy Corp. (the "**Corporation**") in fulfilling its oversight responsibilities with respect to the Corporation's accounting and financing reporting processes and the audit of the Corporation's financial statements, including oversight of:

A. the integrity of the Corporation's financial statements;

B. the Corporation's compliance with legal and regulatory requirements;

C. the external auditors' qualifications and independence and the performance of the audit processes;

D. the financial information and the internal controls associated with the preparation of information, that will be provided to the shareholders and others;

E. the Corporation's risk management, legal compliance and ethics, which management and the Board have established; and

F. such other matters required by applicable laws and rules of any stock exchange on which the Corporation's shares are listed for trading.

While the Committee has the responsibilities and powers set forth in its terms of reference, it is not the duty of the Committee to prepare financial statements, plan or conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate and are in accordance with International Financial Reporting Standards and applicable rules and regulations. Primary responsibility for the financial reporting, information systems, risk management, and disclosure controls and internal controls of the Corporation is vested in management.

II. COMPOSITION AND OPERATIONS

A. The Committee shall be composed of not fewer than three directors, all of whom are "independent"[1] under the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Corporation's shares are listed for trading.

B. All Committee members shall be "financially literate,"[2] and at least one member shall have "accounting or related financial expertise" as such terms are interpreted by the

[1] Committee members must be "independent", as defined in Sections 1.4 and 1.5 of National Instrument 52-110 – *Audit Committees* ("NI 52-110").

[2] The Board has adopted the NI 52-110 definition of "financial literacy", which is an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

Board in its business judgment in light of, and in accordance with, the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Corporation’s shares are listed for trading. The Committee may include a member who is not financially literate, provided he or she attains this status within a reasonable period of time following his or her appointment and providing the Board has determined that including such member will not materially adversely affect the ability of the Committee to act independently.

C. No Committee member shall serve on the audit committees of more than two other public issuers without prior determination by the Board that such simultaneous service would not impair the ability of such member to serve effectively on the Committee.

D. The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in the Board Manual.

E. The Corporation's external auditors shall be advised of the names of the Committee members and will receive notice of and be invited to attend meetings of the Committee, and to be heard at those meetings on matters relating to the auditor's duties.

F. The Committee may request any officer or employee of the Corporation, or the Corporation’s legal counsel, or any external or internal auditors to attend a meeting of the Committee to provide such pertinent information as the Committee requests or to meet with any members of, or consultants to the Committee. The Committee has the authority to communicate directly with the internal and external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or shareholders.

G. The Committee shall have the authority to select, retain, terminate and approve the fees and other retention terms of special independent legal counsel and other consultants or advisers to advise the Committee, as it deems necessary or appropriate, at the Corporation’s expense.

H. The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of (i) compensation to the external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit review or attest services for the Corporation, (ii) compensation to any advisers employed by the Committee and (iii) ordinary administrative expenses of the Committee that are necessary or appropriate for carrying out its duties.

I. The Committee shall meet periodically, but no less than quarterly, with the Chief Financial Officer, and the external auditors in separate executive sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately and such persons shall have access to the Committee to bring forward matters requiring its attention. However, the Committee shall also meet periodically without management present.

III. DUTIES AND RESPONSIBILITIES

Subject to the powers and duties of the Board, the Committee will perform the following duties:

A. Financial Statements and Other Financial Information

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes the responsibility to:

i) review and recommend approval of the Corporation's annual financial statements, MD&A and earnings press release and report to the Board of Directors before the statements are approved by the Board of Directors;

ii) review and recommend approval for release the Corporation's quarterly financial statements, MD&A and press releases and report to the Board of Directors before the statements are approved by the Board of Directors;

iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the public disclosure referred to in items (i) and (ii) above, and periodically assess the adequacy of those procedures; and

iv) review the Annual Information Form and any Prospectus/Private Placement Memorandums.

Review, and where appropriate, discuss:

v) the appropriateness of critical accounting policies and financial reporting practices used by the Corporation;

vi) major issues regarding accounting principles and financial statement presentations, including any significant proposed changes in financial reporting and accounting principles, policies and practices to be adopted by the Corporation and major issues as to the adequacy of the Corporation's internal controls and any special audit steps adopted in light of material control deficiencies;

vii) analyses prepared by management or the external auditor setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative International Financial Reporting Standards ("IFRS") methods on the financial statements of the Corporation and any other opinions sought by management from an independent or other audit firm or advisor with respect to the accounting treatment of a particular item;

viii) any management letter or schedule of unadjusted differences provided by the external auditor and the Corporation's response to that letter and other material written communication between the external auditor and management;

ix) any problems, difficulties or differences encountered in the course of the audit work including any disagreements with management or restrictions on the scope of the external auditor's activities or on access to requested information and management's response thereto;

x) any new or pending developments in accounting and reporting standards that may affect the Corporation;

xi) the effect of regulatory and accounting initiatives, as well as any off-balance sheet structures on the financial statements of the Corporation and other financial disclosures;

xii) any reserves, accruals, provisions or estimates that may have a significant effect upon the financial statements of the Corporation;

xiii) the use of special purpose entities and the business purpose and economic effect of off balance sheet transactions, arrangements, obligations, guarantees and other relationships of Corporation and their impact on the reported financial results of the Corporation;

xiv) the use of any "pro forma" or "adjusted" information not in accordance with generally accepted accounting principles;

xv) any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements; and

xvi) accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate.

B. Risk Management, Internal Control and Information Systems

The Committee will review and discuss with management, and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes the responsibility to:

i) review the Corporation's risk management policies and processes with specific responsibility for credit & counterparty, market & financial, and risks as identified from time to time; and

ii) review management steps to implement and maintain appropriate internal control procedures including a review of significant policies.

C. External Audit

The external auditor is required to report directly to the Committee, which will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

i) review and recommend to the Board, for shareholder approval, the appointment of the external auditor;

ii) review and approve the annual external audit plan, including but not limited to the following:

a) engagement letter between the external auditor and financial management of the Corporation;

b) objectives and scope of the external audit work;

c) procedures for quarterly review of financial statements;

d) materiality limit;

e) areas of audit risk;

f) staffing;

g) timetable; and

h) compensation and fees to be paid by the Corporation to the external auditor.

iii) meet with the external auditor to discuss the Corporation's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;

iv) maintain oversight of the external auditor's work and advise the Board, including but not limited to:

a) the resolution of any disagreements between management and the external auditor regarding financial reporting;

b) any significant accounting or financial reporting issue;

c) the auditors' evaluation (if applicable) of the Corporation's system of internal controls, procedures and documentation;

d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;

e) any other matters the external auditor brings to the Committee's attention; and

f) evaluate and assess the qualifications and performance of the external auditors for recommendation to the Board as to the appointment or reappointment of the external auditor to be proposed for approval by the shareholders, and ensuring that such auditors are participants in good standing pursuant to applicable regulatory laws.

v) review the auditor's report on all material subsidiaries (if applicable);

vi) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation:

a) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors, including a list of all relationships between the external auditor and the Corporation that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation;

b) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors; and

c) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

vii) annually request and review a report from the external auditor regarding (a) the external auditor’s quality-control procedures, (b) any material issues raised by the most recent quality-control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues;

viii) review and pre-approve any non-audit services to be provided to the Corporation or any affiliates by the external auditor's firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit;

ix) review the disclosure with respect to its pre-approval of audit and non-audit services provided by the external auditors; and

x) meet periodically, and at least annually, with the external auditor without management present.

D. Compliance

The Committee shall:

i) Ensure that the external auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;

ii) Disclose any specific policies or procedures adopted for pre-approving non-audit services by the external auditor including affirmation that they meet regulatory requirements;

iii) Assist the Governance and Human Resources Committee with preparing the Corporation's governance disclosure by ensuring it has current and accurate information on:

a) the independence of each Committee member relative to regulatory requirements for audit committees;

b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and

c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member; and

iv) Disclose, if required, if the Corporation has relied upon any exemptions to the requirements for committees under applicable securities laws and rules of any stock exchange on which the Corporation's shares are listed for trading.

E. Other

The Committee shall:

i) establish and periodically review procedures for:

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

e) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other matters that could negatively affect the Corporation, such as violations of the Code of Business Conduct.

ii) review and approve the Corporation's hiring partners, employees and former partners and employees of the present and former external auditor;

iii) review insurance coverage of significant business risks and uncertainties;

iv) review material litigation and its impact on financial reporting;

v) review policies and procedures for the review and approval of officers' expenses and perquisites; and

vi) review the terms of reference for the Committee at least annually and otherwise as it deems appropriate, and recommend changes to the Board as required. The Committee shall evaluate its performance with reference to the terms of reference annually.

IV. ACCOUNTABILITY

A. The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial and other matters considered by the Committee relative to the Corporation.

B. The Committee shall report its discussions to the Board by maintaining minutes of its meetings and providing an oral report at the next Board meeting.